ALJ/km/vdl

DEC 28 1982

RECEIVED
DEC 23 1982

83-692

Decision 82-12-055 December 13, 1982

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY for authority to increase rates charged by it for electric service.	Application 61138 (Filed December 18, 1981)

(See Appendix A for appearances.)

TABLE OF CONTENTS

Subject | Page

INTERIM OPINION

I. SUMMARY OF DECISION

This decision authorizes Southern California Edison Company (Edison) to increase electric rates by $580,935,000 for test year 1983. Of this amount, base rates are increased by $566,758,000; the Annual Energy Rate is increased by $9,177,000; and the Conservation and Load Management Adjustment Clause rate is increased by $5,000,000. The Federal Economic Recovery Tax Act (ERTA) of 1981 is responsible for $103.6 million of the base rate increase. Another $7.9 million of the increase is due to the effects of the Federal Tax Equity and Fiscal Responsibility Act of 1982.

Edison originally requested a total base revenue increase of $1,247.5 million. Due to agreements reached with Commission staff on a number of issues, and later use of lower inflation rates, Edison has reduced its request during the course of the rate case to $816.7 million.

The decision provides Edison with a 16.00% return on equity which translates to a 12.55% rate of return on rate base for 1983. Edison requested a 19% return on equity. The reduction in revenue requirement due to the lower adopted return is $124.0 million.

The adopted return on equity reflects current financial conditions, among other factors. The additional cash flow resulting from ERTA and the adoption of an electric revenue adjustment mechanism (ERAM) should reduce the risks realized by Edison.

Because of the difficulty in estimating total electric sales for the test year, we adopt an ERAM for Edison. We do not adopt an adjustment for billing lag as requested by Edison. The ERAM will adjust base rate revenues for changes in revenue due to unexpected fluctuations in sales during the test period, either in total sales level or in the distribution of kilowatt-hour (kWh) sales among different tariff schedules. To the extent that electric sales and resulting revenues are higher or lower than forecasted, Edison or its ratepayers will be made whole.

The adopted revenue requirement reflects the most currently available forecast of inflation for 1982 and 1983 made by Data Resources, Incorporated. This forecast is used to determine nonlabor escalation rates for 1982 and labor and nonlabor escalation rates for 1983.

Several reductions are made to the level of operating expenses requested by Edison. The major reductions are the following:

1. Deferred maintenance expense of about \$34.9 million is disallowed. Edison had stipulated to a four-year amortization of this amount.
2. A portion of the allowance for funds used during construction (AFUDC) associated with the abandoned fuel cell project is disallowed.
3. Edison's share of the sleeving cost at San Onofre Nuclear Generating Station (SONGS) Unit 1 is considered extraordinary maintenance expense and amortized over four years. The final three of the four annual allowances included in rates shall be subject to refund pending further analysis by the Commission's General Counsel of the prudence of Edison's conduct in regard to its potential legal remedies relating to the sleeving expenditures.
4. Edison's share of the cost of clean-up of the Three Mile Island facility is disallowed.
5. Edison's proposal to establish a methodology for the recovery of the costs of major abandoned projects on an estimated basis is rejected.
6. A penalty which has the revenue equivalent of 10 basis points on Edison's return on equity for 1983 and 1984 is assessed for Edison's failure to comply with the avoided cost pricing policies adopted by this Commission.

The decision authorizes Edison to fund its research, development, and demonstration program at $24.0 million in 1983, which is 14% higher than the 1982 level of funding. Edison is given discretion to allocate the authorized revenues among the programs for which it requested funding but is expected to devote funding to programs which provide special benefits to Edison's service territory. A 20% across-the-board cut is made to the amount requested by Edison.

The decision authorizes $41.9 million for conservation and load management program expenses during 1983. This compares to Edison's requested funding level of $77,990,000. Edison is given discretion to reallocate up to $2.5 million among individual programs. Reallocation of more than $2.5 million among the individual programs, or reallocation to or from the major categories of Residential Conservation, Nonresidential Conservation, and Load Management shall be made the subject of an advice letter filing. In addition to the approved level of expenses, equipment costs for two load management programs are placed in rate base.

The decision disallows requested levels of funding for several specific conservation and load management programs. In addition, a 20% across-the-board cut is applied.

This rate case has been reopened, and today's decision is an interim order, for further consideration of Edison's proposed residential Demand Subscription Service (DSS) load management program. Program funding for DSS will be granted, if warranted, in a final order which is anticipated in early 1983.

Edison is authorized to file for an attrition allowance in 1984 which reflects the most recent estimates of inflation in 1983 and 1984. We have established a specific attrition rate adjustment mechanism for Edison to follow.

A typical residential customer electric bill for 500 kWh will increase from $36.93 to $38.47. The two-tier residential rate

design is retained, and a $2.00 minimum charge is implemented to allow Edison to recover from very small users a portion of its fixed costs incurred in providing electric service.

II. Introduction

A. Procedural Summary

On September 15, 1981 Edison tendered for filing its notice of intention (NOI) to file a general rate increase application for authority to increase its base rates[1] for electric service to its retail customers, including customers on Santa Catalina Island.[2] The tender was made in compliance with the requirements of the Commission's Regulatory Lag Plan for major utility general rate cases as prescribed by Resolution M-4706 dated June 5, 1979. The tender was accepted for filing as NOI 60 on October 19, 1981. On December 18, 1981, Edison filed this application for authority to raise its base rates effective January 1, 1983 to yield an increase in gross revenues of $1,247.5 million in the test year 1983.

---

[1] Base rates exclude all energy costs and most costs directly related to procurement and handling of energy. Under Commission procedure, Edison is permitted to recover reasonably incurred energy costs through the mechanism of an Energy Cost Adjustment Clause (ECAC) in its filed tariffs. The reasonableness of Edison's fuel and purchased power costs, as reflected in the rates actually charged the electricity user, are subjected to full analysis and testing in separate ECAC rate applications which are filed with this Commission from time to time.

[2] In response to a petition filed by Edison, the Commission issued Decision (D.) 82-03-059 dated March 16, 1982, an interim opinion and order authorizing the base-rate cost of service for Santa Catalina Island electric customers to be included in Edison's mainland retail base-rate cost of service for purposes of this application.

At the second prehearing conference on March 4, 1982, Edison announced that it was stipulating to certain items in the Commission staff's (staff) presentation for purposes of this proceeding. The net result of Edison's stipulation was to reduce its estimate of the test year 1983 revenue requirement by $280.2 million. At the oral argument held on August 12, 1982, Edison stipulated to additional issues totalling $150.6 million. These stipulations have had the effect of reducing the amount of the rate increase being requested for the test year 1983 from $1,247.5 million to $816.7 million. Except where noted, the tables throughout this decision reflect the lower figure of $816.7 million in the columns presenting test year figures at Edison's proposed rates.

For the second or attrition year of the two-year period integral to the Regulatory Lag Plan, Edison requests authority to further raise its rates by a single step increase effective January 1, 1984. This step increase would yield an additional $169.3 million in gross revenues in the attrition year 1984. Edison contends that this further increase is needed to offset the impact of financial and operational attrition on the utility's ability to earn a reasonable return on its common equity through 1984.

Edison's most recent prior request for a general increase in rates was Application (A.) 59351, which was also filed under the Regulatory Lag Plan. D.92549 in that proceeding authorized Edison to file base rates effective January 1, 1981, which increased gross revenues by approximately $294 million during the test year 1981. The decision also authorized a further change in rates effective January 1982 to produce an increase in gross revenues of approximately $92 million during the attrition year 1983. The rates authorized by D.92549 were designed to produce over the two-year period an 11.2% return on rate base for Edison's California jurisdictional operations, corresponding to a 14.95% return on common equity.

The application states that an increase in base rates is needed at this time because of a combination of circumstances, which include the following:

> "a. Rates based on the 1981 level of operations, even with the attrition adjustment in 1982, are not adequate to produce the rate of return on rate base required by the Company. Experienced and projected inflation rates indicate that earnings will continue to decline unless the rate relief requested in this Application is granted.
>
> "b. The experience and projected increase in imbedded senior capital costs, because of higher interest and dividend rates for new issues, will increase the composite cost of capital, even without an increase in the allowed return on common equity.
>
> "c. Edison's common stock continues to sell below book value. This condition indicates that (1) the Commission's allowance of return on common equity and return on rate base is inadequate, and (2) the Company's persistent inability to realize an adequate level of earnings continues to cause investor disfavor. An allowance in rate of return on common equity that will allow Edison to issue new common equity at or above book value is essential to meet the Supreme Court's tests prescribed in Bluefield and Hope .
>
> "d. Edison's cash flow has declined to the point that the Company's financial integrity is threatened. For 1981 and 1982, it is estimated that the Company's cash flow deficiency will be over $722 million."

The application requests that, among other things, the Commission:

> "a. Improve Edison's financial integrity by:
>
> > "1. Authorizing, and providing the ability to earn, a 19% return on common equity.

"2. Adopting normalized tax accounting.

"3. Awarding Edison a conservation/load management incentive.

"b. Increase funding levels to:

"1. Expand Edison's conservation/load management program.

"2. Recognize operation and maintenance expenses which reflect system requirements.

"3. Promote additional research, development, and demonstration programs.

"4. Cover the cost of the facilities to be added to serve customers."

Edison estimates that the proposed rates would produce a rate of return on rate base of about 14.19% on California jurisdictional operations. The requested increase does not include the cost of owning, operating, and maintaining the facilities at the San Onofre Nuclear Generating Station (SONGS) Unit 2 and Unit 3.

At the time the application was filed, the projected SONGS in-service dates were June 1982 for Unit 2 and July 1983 for Unit 3. The application states that the greater base-rate revenue requirement

related to these new generating facilities would be made the subject of separate applications.[3] Separate applications are appropriate because there will be significant increases in revenue requirement associated with Units 2 and 3, and the timing of their transfer to rate base should coincide with their being reflected in Edison's rates. Edison states that the resulting increases will be offset by reductions in ECAC charges because its revenue requirement will be reduced by the lowering of system-average fuel expense when electricity is being produced by Units 2 and 3.

On November 4, 1982, TURN filed a petition to reopen this proceeding for the limited purpose of receiving evidence on the most recent rates of inflation and cost of capital to be used to determine the adopted test year results of operation and authorized rate of return for Edison.

The City of West Covina and CVAG each joined in TURN's petition to reopen this proceeding.

Edison filed a response in opposition to the filed petitions.

In this decision, we are adopting a revenue requirement and authorized rate of return for Edison in 1983 based on the latest update of the data introduced by parties in this proceeding. As discussed further in this opinion we have relied on the most recent Data Resources, Inc. (DRI) forecast of the Consumer Price Index and the Producer Price Index for 1982 and 1983 in developing test year 1983 expenses. We also have devised an attrition allowance for 1984 which will adjust attrition year expense levels based on the fall 1983 DRI forecast of inflation recorded in 1982 and 1983, and projected for 1984.

---

[3] A.82-02-40 was filed February 18, 1982 for SONGS Unit 2. As yet, no application has been filed for Unit 3.

In addition we have recognized Edison's actual issues of indebtedness during 1982 in determining the embedded cost of debt for 1982. This results in a downward adjustment in Edison's cost of debt from the estimates proposed by staff and Edison in this proceeding. We have adjusted further the cost of debt for 1983 to reflect the decline in interest rates which has occurred since this summer. We have also reflected current economic conditions and trends in authorizing a return on common equity for Edison. We discuss these adjustments in more detail in Section IX on rate of return.

In adjusting the adopted results of operations and rate of return for Edison by recognizing lower inflation levels and lower costs of financing we believe that we have met the petitioners' concerns. We do not believe that a further hearing is necessary, and will deny each of the petitions.

B. Public Hearings

Following two prehearing conferences held in Los Angeles on January 5 and March 4, 1982, 63 days of public hearing were held in this matter. In early March three days of hearing were scheduled in Palm Desert, Visalia, and Los Angeles, each with an afternoon and an evening session, especially for the purpose of receiving testimony and statements directly from members of the public. A total of 128 members of the public presented testimony at these March hearings, nearly all of whom protested the magnitude of the proposed rate increase. None complained about the quality of electric service they were receiving. All told, well over 1,000 Edison customers attended the six sessions.

Commencing in early March and continuing into July, extensive hearings were held in Los Angeles and San Francisco on the substantive issues raised by the application. Testimony and exhibits were presented on all aspects of the application by Edison and the staff. The California Farm Bureau Federation (CFBF), the California

Retailers Association (CRA), the California Manufacturers Association (CMA), the California Industrial Energy Consumers (CIEC), Toward Utility Rate Normalization (TURN), and the Federal Executive Agencies (FEA) participated through the presentation of witnesses and exhibits and the cross-examination of other witnesses on the subjects relating to revenue requirement, revenue allocation, and rate design. The Coachella Valley Association of Governments (CVAG) presented evidence on those subjects as well as revenue requirement and the Public Utility Regulatory Policies Act of 1978 (PURPA) compliance; a group of Christian Science Churches (CSC) made a presentation respecting demand charges; the California Public Safety Radio Association (CPRA) presented a witness in opposition to Edison's proposed expansion of its radio-controlled residential load management program; the Western Mobilehome Association (WMA) made a presentation regarding the rate schedules applicable to mobile home parks; the California Community and Junior College Association (CCJCA) made a presentation on conservation; Professional Community Management and Mutual Housing Corporations Inside Leisure World (Leisure World) made a presentation regarding rate design as well as a presentation in opposition to the increase; and California Association of Utility Stockholders (CAUS) presented an exhibit on the subject of rate of return.

The matter was taken under submission subject to the following: receipt of certain late-filed exhibits, which have been received; the filing of opening briefs on August 11, 1982; the filing of closing briefs on August 26 1982; and oral argument before the Commission en banc, which was held on August 12, 1982.

C. Edison's Electric Operations

Edison sells electricity as a public utility in a 50,000-square mile service area within 15 counties in central and southern California. The estimated population of this service area exceeds 8.6 million. Retail electrical service is furnished within 800 cities and communities through the facilities of its interconnected

and integrated utility system. Edison also sells electricity for resale to the Cities of Anaheim, Azusa, Banning, Colton, Riverside, and Vernon. Electric power is sold to, purchased from, or interchanged with certain nonassociated utilities, muncipalities, cooperatives, and public authorities, including the State of California, the U.S. Department of Interior, and the Bonneville Power Administration.

Edison owns and operates 36 hydroelectric plants, 12 gas- and oil-fueled thermal-electric generating plants, and one diesel-electric plant. It operates one coal-fueled thermal-electric plant, owned jointly with others, one 80%-owned thermal-electric nuclear plant, and an electric distribution system owned by the City of Vernon. It owns jointly with others, who operate them, one coal-fueled thermal-electic generating plant and one gas- and oil-fueled generating plant. Edison has a combined effective operating capacity under optimum conditions of about 13.4 million kilowatts (kW). These plants, together with transmission and distribution systems and a related communications system, are all located in central and southern California and Nevada with the exception of the generating unit Edison owns jointly with others at Yuma, Arizona, and the jointly owned coal-fueled electric generating plant at Four Corners in New Mexico. In addition, Edison has available to it about 1.2 million kW of firm capacity under terms of power purchase agreements and 350,000 kW of effective operating capacity at the Hoover Dam power plant. Consumption of electricity by Edison's 3.2 million customers totaled 62.5 billion kilowatt-hours (kWh) in 1981.

III. Operating Revenues

A. Electric Revenue Adjustment Mechanism

The purpose of the electric revenue adjustment mechanism (ERAM) is to adjust base rate revenues for changes in revenue due to

unexpected fluctuations in sales during the test period, either in total sales level or in the distribution of kWh sales among different tariff schedules. Through the application of a revenue adjustment mechanism, rates are changed to reflect the difference between authorized and recorded sales levels. The utility is afforded a better opportunity to earn its authorized rate of return during the test year and the attrition year. The ratepayer is, in turn, afforded protection, because the mechanism ensures that the utility retains no more than the authorized amount of base rate revenue. Furthermore, the adoption of a revenue adjustment mechanism is effective in eliminating disincentives for the utility to promote the conservation and rate design policies enunciated by this Commission.

It is unrealistic to expect that all of the key assumptions reflected in a revenue forecast will be borne out during the two-year period for which base rates are being set. Unforeseen and unpredictable factors which are beyond the control of the utility usually cause recorded base rate revenue to be larger or smaller than the adopted test-period level of base rate revenue.

Among revenue forecasting considerations that have a high degree of uncertainty for an electric utility are the following key factors:

a. The effect on electricity sales of the increases in rates.

b. The response of customers to the utility's conservation programs in reducing their energy consumption.

c. The impact of weather on electricity sales.

d. The uncertainty of the economy, including the impacts of inflation and unemployment on electricity sales.

e. The effect of rate design on the total revenue from a particular customer class.[4]

f. The gain or loss of large commercial and industrial customers with attendant shifts and changes in electricity sales.

All of the above factors may cause fluctuations in sales levels which produce revenues which differ from the revenue levels authorized in the test year.

We have already adopted an ERAM for Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) which adjusts revenues due to those factors which affect sales. The staff supports the adoption of an ERAM for Edison in this proceeding. Staff recommends the establishment of a three-times-per-year adjustment of rates. The adjustments would be scheduled to coincide with ECAC proceedings in order to minimize the frequency of rate changes and to maintain the magnitude of overcollections, undercollections, and interest accumulations at a manageable level. Because electricity sales vary according to season, the staff proposal would establish an appropriate schedule of authorized base rate revenues with which to match the monthly base rate revenues under recorded sales levels. This arrangement would also contribute to rate stability by minimizing the size of rate fluctuations.

A number of the parties including CRA, CMA, CIEC, CFBF, and TURN oppose the ERAM concept on the bases that it would detract from the conservation effort and it would shift a stockholder's risk to the ratepayers. We are of the opinion that any such effects are more

---

[4] For example, under a two-tier rate within the residential class, more sales than forecasted for the test year may fall within the lifeline tier instead of the second tier. Since the lifeline tier is at a lower rate than the second tier, less revenue than estimated will result in the test year. An ERAM would adjust for the difference between the estimated and actual revenues.

than offset by the advantages that accrue to the ratepayer and stockholder alike.

The staff proposal would establish an ERAM similar to the mechanisms already adopted for PG&E and SDG&E. After consideration of the record on this subject, we are of the opinion that we should adopt an electric revenue adjustment mechanism, as described in Appendix B. The adopted ERAM will apply to the Annual Energy Rate, as well as to base rates, consistent with the ERAM for PG&E and SDG&E.

B. Billing Lag

Edison entitles its ERAM proposal "Base Rate Revenue Adjustment Clause (BRRAC)." The major difference from staff's proposed ERAM is that BRRAC reflects in rates the difference between authorized and recorded revenues due to billing lag which, assertedly, causes a revenue deficiency which should be recovered through the BRRAC mechanism.

The ERAM tariffs adopted for PG&E and SDG&E created an Electric Revenue Adjustment Account (ERAA). The ERAA tracks for a given month the difference between the amount of authorized base-rate revenue from adopted sales levels and the amount of recorded base-rate revenue from recorded sales. The billing lag issue concerns the method of calculation under an ERAM tariff provision of the base-rate revenue to be credited to Edison's ERAA for January 1983, the first month that the base rates established by this order will be effective.

Billing lag, as that term is used by Edison in the ERAM (or BRRAC) context, occurs because an Edison bill issued to a customer in January 1983 will most likely include sales made in December 1982 and January 1983. Ideally, for ratemaking purposes, all customers would be billed on the last day of each month; thus, their bills would include sales made in that month only. However, reading meters and billing customers can be more efficiently performed by spreading the work throughout the month. The necessary spreading is achieved

through the use of billing cycles, i.e., different groups of customers are billed for a past period's usage on different days. Thus, for all but a relatively few customers, the monthly billing period (and the resultant bill) reflects electricity consumption in parts of two calendar months.

As a consequence, when rates are increased effective January 1, bills sent out in January include December sales at the prior rates and January sales at the new rates. Hence, recorded January revenues reflect, in part, sales at the old, lower rates. By February all customers are being billed at the new, higher rates and there is no billing lag question as to whether that month's and subsequent months' revenues will satisfy revenue requirement.

It is Edison's position that a revenue deficiency results because of billing lag. According to Edison an ERAM (or BBRAC) should function so as to match recorded revenues for 1983 to the test period revenue requirement. To do this, a billing lag adjustment factor would need to be applied through the operation of the ERAA. Since the lag at issue amounts to approximately 15 days (one-half of the first monthly billing period in 1983), such a billing lag adjustment factor would be 1/24 of the increase in revenue found reasonable for the test year. The use of the factor would result in Edison's recorded revenue (and the ratepayers' collective bill) for 1983 being increased by approximately $34 million when applied to Edison's modified revenue increase request of $816 million.

The underlying assumption of Edison's position is that all revenues authorized during the test year should actually be collected during the test year. Edison claims that otherwise it cannot earn its authorized rate of return because recorded revenues will always be less than authorized due to the lag in revenues which occurs in the month of January.

One flaw in Edison's position which staff points out is that it ignores the fact that all expenses authorized during the test year are not actually paid during the test year. As a result, authorized expenses will always be greater than expenses actually paid in the test year. For example, Edison is given an expense allowance for state and federal income taxes which are incurred in a particular calendar test year but actually are paid beyond that year. Staff contends that since the full annualized increase in expenses does not occur during the test year, it is unreasonable to expect the increased revenue requirement to be received during the test year.

We disagree with Edison that a purpose of ERAM was to enable Edison to recover the so-called billing lag through ERAM. We further strongly disagree with Edison that without recognition of the billing lag it would not have the opportunity to earn its authorized rate of return. Edison has a mistaken understanding that test year ratemaking and calendar year operating results should be identical.

Under test year ratemaking the Commission adopts a set of rates which will provide the necessary revenue requirements to recover reasonable expenses, taxes, and a reasonable return on the investment necessary to provide service to the utility's customers during the estimated test year period. For test year ratemaking purposes, the Commission assumes a perfect matching of revenues, expenses, investment, and return on such investment. In order to more closely track the test year with the calendar year, the Commission under its Rate Case Processing Plan has attempted to establish general rate case changes effective on the first of the calendar year. In adopting this practice, the Commission did not intend to make the ratemaking test year synonymous with calendar year recorded results of operations.

The Commission is well aware that under Edison's accounting practices, revenues for services rendered in a given calendar year are not necessarily recognized in that calendar year. Edison's use of ERAM to attempt to obtain additional revenues to make up a perceived revenue deficiency resulting from its reluctance to recognize unbilled revenues for services rendered in 1982 represents an unreasonable interpretation of ERAM. Only the company's accounting methods prevent 1982 revenues from being recognized in total in the calendar year and result in part of 1982 revenues being recognized in the month subsequent to the end of the calendar year.

If Edison is seriously concerned about obtaining a perfect matching of revenues with expenses, it has the option of recognizing revenues for services rendered in December as unbilled revenues. We can understand Edison's reluctance to make such an accounting change since there is a possibility that the Internal Revenue Service (IRS) would require that such revenues also be reported for income tax purposes. From a ratemaking standpoint, however, Edison should also be aware that our adopted test year rates include a provision for income taxes based on the authorized level of revenues, and in deferring recognition of such income it is in fact deferring the tax liabilities to the subsequent tax year. The matching of revenues and expenses which Edison seeks through ERAM is obtainable by the simple accounting practice of recognizing unbilled revenues without misusing ERAM or by placing an additional burden on ratepayers by making them pay 1983 rates for services provided in December 1982 at 1982 expense and return levels.

A similar position was developed by PG&E which we found unpersuasive in D.82-04-117 issued earlier this year. In affirming our position on ERAM as stated above, we wish to emphasize that we have carefully reviewed and considered in their entirety the extensive showings made on this record by staff, PG&E and SDG&E, as well as that made by Edison.

We will adopt for Edison the ERAM tariff attached to the order as Appendix B, which should lay to rest the billing lag issue, as well as significantly promote the proper and effective administration of the ERAM we are authorizing for Edison.

C. Electricity Sales Forecasts

Edison's stipulation to the staff sales forecast and revenue estimate was conditioned upon our making provision for the billing lag adjustment in an ERAM. Thus, our rejection of the inclusion of such a provision in the adopted ERAM has the effect of requiring us to review and resolve the issue of the differences between the sales forecasts and revenue estimates of Edison and the staff.

Edison's original forecast of test year 1983 total net electricity sales of 56.33 billion kWh, as reflected in the application, was prepared in May 1981 and was based on recorded data through April 1981. In January 1982, Edison prepared a revised sales forecast for 1983 which was based on recorded data through December 1981. Edison's revised test year forecast of 58.48 billion kWh thus includes eight more recent months of actual sales experience. Recorded sales for 1981 were at a level about 2.7% higher than reflected in the original forecast. Edison attributes the higher level of 1981 sales to greater customer growth, higher-than-normal summer temperatures, lower electricity prices, and increased activity in the oil extraction and defense industries.

The staff test year sales forecast was prepared later than Edison's original forecast. It reflects recorded sales experience the first 10 months of 1981 and is based on different assumptions than Edison uses. As shown in Table III-1, the staff forecast of total net sales of 59.36 billion kWh is quite close to Edison's revised figure, being only 1/10 of 1% lower. Considering the difficulties involved in making accurate electricity sales estimates,

this cannot be regarded as a meaningful difference; 1/10 of 1% is very small in magnitude compared to the probable error inherent in the sales estimating methodologies of Edison and the staff. Having considered both forecasting methodologies, we will adopt staff's test year estimate of jurisdictional base-rate operating revenues at present rates of $1,565 million, as shown in Table III-2, as being fairly and reasonably reflective of the sales forecasting data of record in this proceeding.

TABLE III-1

COMPARISON OF ELECTRICITY SALES
FORECASTS BY CUSTOMER GROUPS

Test Year 1983
(Millions of kWh)

Customer Group	Edison Estimate	Staff Estimate	Difference
Domestic*	16,593.8	16,588.8	5.0
Lighting-Small and Large Power*	16,195.9	16,232.1	(36.2)
Time-Of-Use	18,909.3	19,061.8	(152.5)
Agricultural and Pumping*	1,843.4	1,809.7	33.7
Street and Area Lighting*	497.6	498.7	(1.1)
Fringe	6.5	6.5	0
Public Authority-SWP	546.0	522.0	24.0
Public Authority-MWD	508.0	206.0	302.0
Subtotal	55,100.5	54,925.6	174.9
Resale	4,433.5	4,433.5	0
Total	59,534.0	59,359.1	174.9

(Red Figure)

*Includes Catalina sales

TABLE III-2

COMPARISON OF REVENUE ESTIMATES AT
PRESENT RATES BY CUSTOMER GROUPS

Test Year 1983

(Thousands of Dollars)

Customer Group	Edison Estimate	Staff Estimate	Difference
Domestic*	570,912.3	570,749.3	163.0
Lighting-Small and Large Power*	506,594.6	509,804.5	(3,209.9)
Time-Of-Use	383,613.6	386,816.7	(3,203.1)
Agricultural and Pumping*	53,950.3	55,051.0	(1,090.7)
Street and Area Lighting*	40,792.9	40,788.2	4.7
Fringe	130.0	130.0	0
Public Authority-SWP	2,257.0	2,088.0	169.0
Public Authority-MWD	6.4	6.4	0
Subtotal	1,558,257.1	1,565,424.1	(7,167.0)
Resale	31,156.4	13,543.4	17,613.0
Subtotal	1,589,413.5	1,578,967.5	10,446.0
Other Operating Revenue	36,821.2 **	36,821.2**	0
Total	1,626,234.7	1,615,788.7	10,446.0

(Red Figure)

*Includes Catalina revenues

**CPUC Jurisdictional is $25,228.0

IV. Operating Expenses

A. General

Operating expenses are comprised of all of the costs associated with running the utility, including the labor, materials, and other expenses required to operate and maintain its electric system.

Edison's normal or recurring operation and maintenance (O&M) expenses were forecast using a trending method, as discussed in Section IV.B, Trending. This method requires removal of unusual or nonrecurring costs which would tend to distort the pattern of the recorded data. After trending, the unusual or one-time expenses are added back. For example, for power production, overhaul expenses were treated as adjustments by being first removed from the data to be trended and then added back after trending. This methodology was used by both Edison and the staff. Amounts at issue because of trending differences are set out as separate items throughout the following discussion of operating expenses.

As discussed in Section IV.C, Escalation, operating expense estimates were trended after converting all data to constant 1981 dollars. The results of trending were then adjusted as described in the preceding paragraph, and then escalation factors for 1982 and 1983 were applied to the results to obtain test year figures in 1983 dollars. Both Edison and the staff have employed this methodology, using the respective factors that each adopted. Amounts at issue because of escalation factor differences are also set out as separate items throughout the following discussion.

The differences in expense levels related to the staff recommendation of a 5% limitation to increases in nonunion labor wages in 1982 and 1983 are treated as one lump sum difference. The staff labor escalation factors used in the following discussion of operating expenses do not include the effects of this staff-proposed nonunion wage limitation.

Table IV-1 is a tabulation by accounts and/or groups of accounts of the operating expense issues between Edison and the staff expressed as differences in revenue requirement. Note that in Table IV-1 escalation and trending are set forth separately, in accordance with the preceding discussion.

TABLE IV-1

AMOUNTS AT ISSUE BETWEEN EDISON AND STAFF
Operating Expenses - Test Year 1983

	System Estimate Difference $M	Jurisdictional Revenue Requirement Difference $M
Escalation (All Accounts)	22,379	21,943
Salary Increase Limit	7,222	6,821
Trending (All Accounts)	23,937	23,059
Steam Power Production		
Class III Overhauls	10,448	9,780
Miscellaneous Differences	28	26
Other Power Production		
Class III Overhauls	4,040	3,782
Combined Cycle O&M	1,675	1,568
Fuel Cell Write-Off	1,141	1,068
Nuclear Power Production		
Unit I Sleeving	(6,500)	(6,085)
Miscellaneous Differences	65	61
Power Production (Non-ECAC, Fuel Related)		
Spent Fuel	560	526
Other	397	373
Customer Accounts		
Customer Service Rep.	1,155	1,167
Customer Service and Informational		
Conservation Programs	10,460	10,568
Load Management Programs	5,272	5,326
Administrative and General		
Executive Salaries	(9)	(9)
EEOC Litigation	140	137
Public Awareness	677	660
Insurance - SONGS 1	1,301	1,268
EEI Dues	567	553
Dues & Donations - Other	217	211
TMI Cleanup	525	512
Management Audit	500	487
Office Alterations	242	236
Abandoned Projects	1,565	1,525
Capitalized A&G	(2,737)	(2,668)
Employee Benefits	2,252	2,195
Depreciation Expense	13,293	12,433
Tax Expense		
Income Tax	*	11,531
Ad Valorem Tax	1,311	1,289
Other Taxes	1,542	1,493

* This item was not quantified in Exhibit 151B.

(Red Figure)

B. Trending

1. Edison's Method of Trending

Edison's forecasting method used time-based linear trends to forecast the normal or recurring portions of O&M expenses. The unusual or nonrecurring portions were handled through adjustments to the trend.

Edison explains that it chose to trend O&M expenses because, inflation aside, these costs have been observed to experience steady and consistent growth over the historical base time period (1976-1980) which Edison examined. According to Edison, O&M expenses have grown steadily because of a variety of important underlying factors affecting system performance. The factors include, among others, growth in the electric system, new programs such as conservation/load management, increasing regulatory requirements, and increasing system age. Edison states that it made early attempts at using a multivariate model as suggested by certain staff witnesses, but that the results were often inconclusive and even speculative. Other methods of forecasting were also tried and discarded because Edison believes they produced unrealistic results. The methods included the historical average, which Edison says gave low results, and the exponential time trend, which overstated growth and gave high results. Edison decided, therefore, that a surrogate prediction variable should be used to explain the combined effect of all actions and, of the variables that Edison investigated, time was selected. Edison asserts there is strong empirical justification for using time as the surrogate prediction variable because a trend line based on time in the recorded period of 1976 through 1980 gives accurate results in about 99 cases out of 100.

Having arrived at what it regards as a valid and equitable method of determining total O&M expense, Edison's next step was to extend the generalized results of its time-based linear trends to the labor and nonlabor components of individual Federal Energy Regulatory Commission (FERC) accounts. Edison states that this was readily accomplished because its model of total expense was linear. Edison points out that by the principle of superposition for linear systems of equations, the sum of a group of linear equations predicting individual accounts is equal to a single linear equation predicting the total of those same accounts. Because results with the model based on total O&M expenses were very good, Edison states there was no need for statistical validation of the component accounts. Edison asserts that the method it chose is the only equitable, logical, and consistent means of forecasting expense levels.

2. Staff Position on Trending

The staff, on the other hand, does not acknowledge the applicability of the principle of superposition as relied upon by Edison in the determination of O&M expenses, and argues that it was unable to verify that all unusual, nontrendable expenses had been removed from every account prior to trending. The staff used the trends developed by Edison only where the statistical measures for the separate labor or nonlabor component of each individual account were, in the staff's opinion, good enough to justify a linear trend.

The staff used the following statistical criteria in the evaluation of Edison's trends: an R-squared (coefficient of determination) in excess of 0.60 and a T-statistic of at least 2.0. R-squared is a measure of the amount of variance the trend explains or goodness of fit for the trend line. A low R-squared indicates a significant amount of unexplained variance. The T-statistic indicates the significance of the explanatory variable in predicting the dependent variable. High R-squared and T-statistic values are desirable.

In cases where it believed that the statistics were not good, the staff used historical averages or other methods to estimate 1983 expenses, applying what it regarded as the most appropriate methodology to each account. The staff also analyzed the various adjustments applied to the trended estimates by Edison and, where it deemed appropriate, made substantial changes to them.

As a result of the differences in trending, the staff's estimate for test year 1983 O&M expenses results in an aggregate jurisdictional revenue requirement for all accounts that is $23.1 million lower than Edison's.

3. Discussion of Trending

About half of Edison's request for O&M expenses in 1983 was obtained by trending past normal or recurring expenditures. Thus, the trending methods used both by Edison and by staff deserve close scrutiny.

Ideally, as much pertinent information as is available should be used to explain variations in historical expenses and to project future expenses in each individual component of total O&M expenses. The removal and separate treatment of unusual or nonrecurring costs is a good first step. However, Edison's consistent use of a linear trend equation to estimate the recurring portions of O&M expenses based on expenditures recorded in 1976 through 1980 is overly simplistic. We find convincing staff's rationale for accepting Edison's trend results only if certain statistical criteria are met, and we adopt staff's approach in this respect.

Use of trends based on historic expenditures recorded during 1976 through 1980 to predict total 1983 requirements assumes that expenses will and should increase between 1981 and 1983 in the same way that they increased during the 1976-1980 period. Acceptance of any particular model such as a time-based linear trend further implies that this model accurately describes the changes in past

expenditures. By Edison's own statement, its trending methodology projects O&M expenses for 1981 and 1982 higher than management's target level for these expenses for these years. We believe that Edison's trending method also overestimates reasonable 1983 expense levels.

For some accounts, staff recommends that a budgetary approach be used, to allow examination of funding levels of specific activities. Edison argues that detailed forecasting of all test-year budgets would be burdensome and difficult to implement due to its diffuse nature and because of difficulty in establishing the proper reviews and controls.

Ideally, the decision of which estimating method to use would be made on an account-by-account basis. There are obvious time and budget limitations. However, we would like to see in Edison's next rate case a greater effort on the part of both Edison and the staff to choose and justify forecasting methods which better match the type of growth expected for various subparts of total O&M expenses.

Unless discussed explicitly in the sections that follow, differences in staff and utility trend results are due to staff's use of historical averages for accounts in which Edison's results do not meet staff's statistical criteria. We adopt staff estimates in these accounts.

For some accounts, staff used methods other than historical averages to obtain estimates of 1983 expenses. We discuss staff's recommendations for these accounts in the sections devoted to the specific accounts.

C. Escalation

1. Background

Escalation rates, as employed by both Edison and the staff in this proceeding, are used to obtain inflation-adjusted data for trending O&M expenses and to determine an attrition allowance.

For trending purposes, Edison and the staff used escalation rates to adjust past or recorded O&M expenses and to inflate their respective constant dollar O&M expense forecasts. All past O&M expenses used to project test-year expenses were converted to 1981 constant dollars to remove purely inflationary price changes prior to adjusting and trending. Escalation rates were also used by Edison and the staff to add the expected impact of inflation to estimates for 1981 through 1984.

2. Nonlabor Escalation Issues

In Edison's original showing, which was presented with the application, the utility assumed a 12.3% rate of escalation for labor costs and a composite 12.9% rate for nonlabor costs for 1981, 1982, and 1983. These assumptions were based on information available in April 1981, during preparation of the application. By the time of the second prehearing conference, it became apparent that the actual rate of inflation would be lower than Edison had forecast. Edison then modified its labor escalation rates and proposed a procedure for developing more accurate nonlabor escalation rates. The procedure has the merit of providing the Commission with an opportunity to determine the rate of escalation using more recent forecasts of inflation.

There are four considerations at issue in the procedure: (1) a composite index must be established for assigning the various weights to be given to the indexes used to forecast the nonlabor escalation rates; (2) the time of the forecast must be chosen; (3) the type of forecast to be used must be chosen; and (4) a selection must be made between the use of a point-in-time or a weighted average of several forecasts. These considerations are discussed below:

a. Composite of Indexes

Edison has proposed a composite index which weights the various indexes used to forecast nonlabor escalation rates. The

staff agrees to Edison's composite index; therefore, this consideration is no longer at issue between the two; and we will adopt the composite index they have agreed upon, which is shown in Appendix C.

b. Time of Forecast

Edison originally suggested using the fall of 1982 Data Resources Incorporated (DRI) forecast for developing test year 1983 O&M expenses. The staff proposed using the summer of 1982 forecast, which was the latest available forecast at the time the case was submitted, and Edison agrees to the use of this forecast. We see no reason to rely on the summer DRI forecast since the fall forecast is now available. We will adopt escalation rates based on the fall DRI forecasts which Edison has provided as late-filed Exhibit 154.

c. Type of Forecast

DRI has several different forecasts of escalation rates: "Optimlong", which is an optimistic forecast; "Pessimlong", which is a pessimistic forecast; and "Trendlong", which is the predicted scenario and is DRI's base forecast. The staff proposes to use the Trendlong forecast. Edison contends, however, that Trendlong tends to underestimate inflation by a wide margin. Edison cites, for example, DRI's 1978 Trendlong forecast in which the escalation rate of wholesale prices was understated by 6.1% for 1979 and 8.7% for 1980 compared to the actual escalation rates experienced in those years. To compensate for this alleged tendency to understate the rate of escalation, Edison proposes an average of DRI's Trendlong forecast and Pessimlong forecast. The Pessimlong forecast is based on economic assumptions leading to higher forecasts of inflation than those assumed by DRI for Trendlong. Edison's position is that the averaging of Trendlong and Pessimlong will offset the tendency of the Trendlong forecast to underestimate inflation.

In considering the type of forecast to be adopted, we have fundamental difficulties in accepting Edison's proposal to average

DRI's Pessimlong forecast with the Trendlong forecast. An equally valid argument might be made for averaging in the Optimlong forecast instead. No convincing rationale attaches to Edison's use of the Pessimlong forecast in this manner. We perceive that Edison's approach is self-serving. Edison does not deny but, in fact, relies on DRI's expertise in forecasting. Trendlong is DRI's base economic scenario. We agree with the staff position that the Trendlong forecast should be used.

d. Point in Time vs.
Weighted Average

There is also an issue between Edison and the staff as to whether a point-in-time forecast or a weighted average of several forecasts should be used. The staff recommends a point-in-time approach using the summer of 1982 DRI forecast only. Edison recommends a weighted average of the four most recent DRI forecasts with the later forecasts being assigned greater weight.

Edison points out that DRI's forecasts are based on the latest available recorded data. According to Edison, the near-term forecasts of inflation tend to reflect temporary changes in the rate of escalation. Edison cites, by way of example, that DRI's quarterly 1981 Trendlong forecasts of 1982 escalation for the Consumer Price Index (CPI) varied from a high of 10.2% to a low of 7.9% and that the forecasts for the Producer Price Index (PPI) varied from a high of 12.6% to a low of 6.9%. Edison takes the position, therefore, that any specific forecast of inflation, although it may reflect the current assessment of the rate of escalation, is likely to be too high or too low depending on the point in time during the cycle of inflation that the projection is made.

To mitigate this tendency, Edison proposes the use of a weighted average of the four most recent DRI forecasts. Under Edison's proposal the latest forecast would be weighted 7/16 and the three preceding forecasts would be weighted 5/16, 3/16, and 1/16,

respectively. It is Edison's view that this weighting approach would tend to minimize the shortcomings of using any single forecast, yet still give the greatest weight to the most recent.

We see no merit in Edison's argument. DRI's fall 1982 forecast is based on the most up-to-date information available in this record. We will adopt a point-in-time approach using the fall 1982 forecast.

3. Labor Escalation Issues

For the calculation of labor costs, both Edison and the staff have used a 9% escalation rate for 1982, based on Edison's recent wage agreement with its union employees. Edison has used the 9% rate for all its employees; the staff, however, has recommended that the recognized increase in wages for all nonunion employees be limited to 5%, rather than escalating them on the basis of the union contract.[5]

Staff's recommendation is based on the staff's judgment of the current economic situation. The staff believes that it is inappropriate for Edison's nonunion employees to receive any higher rate of increase in light of the current economic climate of high unemployment, declining inflation rates, and limited salary increases in private industry. The staff supported its position with six newspaper articles which describe wage concessions and layoffs in various industries. The articles include reports on the wage concessions made by union and in some cases, nonunion, employees in return for certain concessions from employers, such as guarantees of job security or granting higher than normal increases when the economy improves.

---

[5] The staff did not restrict wage increases for union employees because of its uncertainty of the Commission's authority to do so. In the staff brief, staff cites legal authority which appears to support a limitation on union wage increases for ratemaking purposes.

The staff's adjustment to nonunion wages and salaries was not contained in the figures shown in Exhibits 43 and 44, its Report on Results of Operations; therefore, it is not broken down by expense accounts but is treated as a lump sum adjustment. Based on staff's estimate of the rate of inflation in 1982 and 1983 the adjustment would amount to $7.2 million for system expenses and $6.8 million for Commission jurisdictional revenue requirement in 1983. The 5% wage increase limitation on nonunion wages would affect all accounts which contain nonunion labor expense. The nonunion payroll amounts to 43.6% of Edison's total labor expenses. Under the staff proposal, Edison could either implement the 5% limitation, or its stockholders could absorb any increase over the limit that Edison's management might see fit to pass on to the nonunion employees. To implement the 5% limitation, Edison would have to ask nonunion employees to accept a 5% wage increase limitation during 1982 and 1983 at the same time union employees are receiving a 9% wage increase for 1982 and a 6.4% increase for 1983. The staff recommendation makes no provision for Edison to make any concessions to labor similar to those described in the articles cited by the staff.

The staff's recommendation assumes that the 5% limitation is in full effect for all of the year 1982. Edison's salary planning for 1982 will have been essentially implemented at the time this decision is issued, making it difficult for Edison's management to implement the 5% limitation in 1982. The alternative would be to implement staff's $7 million nonunion wage limitation proposal solely in 1983. This would require Edison's 6,500 nonunion employees to accept near-zero wage increase at the same time that the 8,500 union employees would be receiving a 6.4% increase. The real world effect of the staff proposal to impute the 5% limitation to 1982, if we were to adopt it for rate setting, would be to deny the inclusion of any nonunion wage increase in the revenue requirement for 1983, while at the same time passing through a 6.4% union wage increase to the ratepayers.

Edison introduced the testimony of a compensation and human resource management consultant who described the impact of staff's recommendation on the company. In Exhibit 140, he offered the opinion that:

1. Staff's reliance on wage concessions made in other industries is not relevant to the electric utility industry.
2. Current levels of unemployment are not high in the electric utility industry; therefore, in order to remain competitive Edison must achieve wage parity with other utilities.
3. Limitations on nonunion wage increases are inequitable and will cause compression between classes of employees.

We perceive a number of infirmities in the staff's nonunion wage limitation proposal, among them:

1. It unnecessarily distinguishes union and nonunion employees. Staff did not find the wage increase for union employees to be unreasonable. It is therefore difficult to understand why a similar increase to nonunion employees is unreasonable.
2. The selection of a 5% wage increase is not well-supported in the record.
3. If implemented by Edison, the wage limitation could lead to internal pay inequities, increased turnover of employees and difficulty in recruiting talented individuals.

We will not adopt the staff's nonunion wage limitation proposal. The record is clear that it is currently reasonable for Edison to afford its nonunion employees the same percentage increase as Edison under contract will pay its union employees.

For 1983 we have adopted union and nonunion labor escalation rates of 6.1%, which are obtained using the staff's method of calculating its 6.4% union labor escalation rate, but

incorporating the fall 1982 DRI forecasts. We believe that this is a more reasonable estimate of inflation based on current and expected trends in the next year.

4. Adopted Escalation Rates

Although both based their projections on DRI forecasts, Edison and the staff differ in the general economic conditions each has assumed in arriving at its recommended escalation rates. Edison's assumptions are the more pessimistic. This results in a difference between their estimated jurisdictional test year 1983 figures for revenue requirement of $21.9 million for all accounts, not including the effect of the staff recommendation to limit nonunion labor costs to 5% annual escalation. The effect of this proposed limitation on nonunion wages increases this difference to $28.7 million.

Table IV-2 shows a comparison of the escalation rates proposed by Edison and the staff, together with those we have adopted for purposes of this proceeding. The rates we have adopted generally follow the methodology proposed by the staff but are based on DRI's fall 1982 Trendlong forecast. We are not adopting the staff's recommendation to limit the escalation of nonunion labor costs to 5% for both 1982 and 1983 as already discussed. Reliance on fall rather than summer data results in a reduction of $7.05 million in 1983 revenue requirements.

TABLE IV-2

COMPARISON OF ESCALATION RATES FOR 1982 AND 1983

	Edison	Staff*	Adopted
Annual Rates			
1982			
Nonlabor	6.2%	4.7%	4.3%
Labor	9.0%	7.3%	9.0%
1983			
Nonlabor	8.5%	6.5%	5.4%
Labor	7.1%	5.8%	6.1%
Compound Factors			
1982-1983			
Nonlabor	1.15227	1.11506	1.09932
Labor	1.16739	1.13523	1.15649

*Includes the staff-proposed limit on the wages of nonunion employees, based on 5% escalation for both 1982 and 1983, using the proportion of 56.4% union labor costs and 43.6% nonunion.

D. Deferred Maintenance

Edison requests recovery of about $34.9 million for deferred maintenance. The amount is determined as follows:

Deferred	1983	1984
	$M	$M
Production expense	30,897	1,733
Transmission expense	1,095	572
Distribution expense	636	0

According to Edison, the level of maintenance expense requested and authorized in Edison's 1980 general rate case fell short of the funds needed to perform maintenance scheduled through 1982. Rather than spend dollars for maintenance beyond those authorized in rates as Edison has done in prior years, Edison decided to defer it in order to increase shareholder dividends and improve the company's earnings. Edison believes

that both the ratepayers and shareholders benefited from management's decision to maintain the company's financial health over the short term.

The staff agrees with Edison that the maintenance deferred must be accomplished or further deterioration may result. Staff, however, is concerned that deferral of maintenance does not conform to good operating practice. By deferring maintenance the utility risks deterioration of the operating efficiency of its plant which ultimately results in reduced reliability and safety. It also can lead to additional fuel costs which are borne by the utility's customers.

In this case, staff recognizes that, historically, Edison's recorded levels of maintenance expense have exceeded authorized levels. This is shown in Table IV-3. Edison's shareholders have absorbed the additional expenses. Staff therefore believes it is reasonable to allow Edison to recover the requested amount of deferred maintenance expense from its ratepayers. Staff proposes that the recovery be spread over four instead of two years. Edison has accepted the staff position.

Although the staff and Edison have agreed on this issue, the fundamental issue remains whether the cost of deferred maintenance should be recovered from ratepayers. In the past Edison has expended maintenance dollars beyond those authorized without seeking recovery from ratepayers. We view this as a consequence of test-year ratemaking in which forecasts of maintenance expense may either be over- or underestimated.

In this case we are concerned that Edison departed from its past practice of spending what was necessary for adequate maintenance, for the purpose of improving its financial condition. We are not persuaded that the lower costs associated with an improved financial condition offset the higher costs associated with deteriorating plant efficiency.

We recognize that Edison's shareholders have consistently borne maintenance expenses exceeding the amounts recognized in rates since 1976. Our allowances for maintenance expenses in test year 1983, discussed in the following sections, are based on Edison's improved budgeting methods and show a 52% increase over the amounts authorized for

test year 1981 from $190.4 million in 1981 to $289.8 million authorized today for 1983. Based on this significant increase, we do not anticipate a recurrence of past underestimates of such expenses.

In our 1981 general rate case decision for PG&E, D.93887, we authorized PG&E to recover in rates a portion of its projected costs of deferred maintenance. The situation there was distinguishable from the present case in that PG&E requested a much smaller amount for deferred maintenance and PG&E's financial condition during the period when maintenance was deferred was substantially more tenuous than was Edison's financial condition during 1982.

For us to authorize Edison's recovery of deferred maintenance expense would establish an undesirable precedent, whereby the utility is effectively guaranteed that it can earn (or exceed) its authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in the assurance that they could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case. This would create a perverse incentive for the utility to defer needed maintenance in the future. Consequently, we will disallow recovery of the $34.6 million requested for deferred maintenance activities in 1983 and 1984.

Our disallowance of this expense for test year ratemaking purposes does not relieve Edison of its responsibility to maintain the operating efficiency of its utility plant in a timely manner. Indeed, we expect Edison to fulfill that responsibility more conscientiously in the future.

TABLE IV-3

POWER PRODUCTION AND TRANSMISSION MAINTENANCE EXPENSE
(Estimated, Adopted, and Recorded - 1976 Through 1981)

Expense Item/ Year	Edison Estimate $M	Staff Estimate $M	Authorized Amount $M	Recorded Amount $M
Power Production Maint. Expense				
1976	48,749	46,533	47,983	60,460
1977	-	-	-	78,913
1978	-	-	-	93,620
1979	76,490	71,217	75,102	104,791
1980	-	-	-	145,735
1981	119,940	106,489	112,202	124,154*
Transmission Maint. Expense				
1976	15,125	14,394	14,843	13,617
1977	-	-	-	14,714
1978	-	-	-	16,554
1979	15,747	14,062	15,747	18,838
1980	-	-	-	19,851
1981	18,409	18,001	18,001	21,540*

* 1981 Recorded is 12-month period ending October 31, 1981.

E. Steam Power Generation Expenses - Excluding Fuel

1. General

Estimated expenses for the majority of steam power generation accounts in 1983 and 1984 exhibit larger increases than can be explained by the inflation and average growth patterns experienced over recorded years 1976-1980 . According to Edison, the higher level of expenses is related to significant increases planned in essential maintenance activities for 1983 and 1984 compared to similar activities accomplished in 1976-1980. This increase in the level of planned maintenance activity for the estimated years over the recorded years is the principal cause of the rapid increase in steam production expenses.

The number of overhauls scheduled for steam production facilities in 1983 and 1984 is greater than the average of the recorded years 1976 through 1980. As a result, overhaul expenses in the future years are projected to be greater than in the recorded period. For example, Edison estimates expenses for steam production overhauls in 1983 and 1984 will exceed those incurred in the 1976-1980 period by an average of $13 million on a 1981-dollar basis.

Because of the slowdown over the past five years in the installation of new generating equipment, the average age of Edison's generating plant has increased. Edison states that this increase in the average age of the steam production facilities is expected to result in significant increases in required maintenance activities for 1983 and 1984 when compared to 1976-1980 levels. On a 1981-dollar basis, Edison expects the increases to amount to $10 million in 1983 and $18 million in 1984. Staff agreed with this cost and included it in its 1983 test year estimate.

In the period through 1984, Edison plans to install new equipment at its steam production plants, including such items as scrubbers, a baghouse, and make-up demineralizers. Edison points out that the installation of these items and other new equipment will require additional funds to be expended for the operation and maintenance of these facilities and that, therefore, the estimates for steam production accounts include $4.8 million in 1983 and $9.4 million in 1984 for O&M expenses for these new items of equipment.

2. Amounts at Issue

In total, Edison's estimates of steam power generation expenses exceed the staff by approximately $27.7 million. Table IV-4 provides the details of this difference segregated according to issue. Table IV-5 shows a comparison of estimates by FERC accounts. While staff and Edison agreed on research, development, and demonstration (RD&D) and deferred maintenance expenditures, we adopt other amounts for these two categories, as discussed in Section V and Section IV.D, respectively.

TABLE IV-4

STEAM POWER GENERATION EXPENSES - EXCLUDING FUEL

Test Year 1983

Item	System Estimates Edison $M	Staff $M	Adopted $M
Class III Overhauls	10,448	-	5,224
Trending	138,348	129,849	129,849
Escalation	32,327	23,630	21,113
RD&D	6,000	6,000	2,574
Deferred Maintenance	5,222	5,222	-
Uncontested	48,227	48,227	48,227
Total	240,572	212,918	206,987

TABLE IV-5

STEAM POWER GENERATION EXPENSES - EXCLUDING FUEL

(Test Year 1983)

Account		Edison $M	Staff $M	Adopted $M
	Operation			
500	Supervision and Engineering	7,297	7,349	7,310
502	Steam Expense	18,719	16,954	16,756
505	Electric Expense	7,885	7,612	7,569
506	Misc. Steam Power Expense	23,555	20,749	17,153
507	Rents	211	211	211
	Subtotal	57,667	52,875	48,999
	Maintenance			
510	Supervision and Engineering	14,007	12,688	12,732
511	Structures Expense	7,628	7,393	6,562
512	Boiler Plant Exp.	101,232	92,783	91,133
513	Electric Plant Exp.	49,184	36,669	37,188
514	Misc. Plant Expense	10,881	10,510	10,373
	Subtotal	182,932	160,043	157,988
	Total	240,599	212,918	206,987

3. Class III Overhaul Expenses

The following definitions are used in th
segregate the overhaul work performed on power pro

> Class I Overhaul Work is defined as all the general maintenance activity Edison it must perform during every overhaul. includes expenses for such activities as opening and closing of boilers and turbi inspections, general repairs, and cleani equipment.

> Class II Overhaul Work is defined as all the maintenance activity that Edison kno must perform during any particular overh which is not of a recurring nature, such those costs identified in Class I. Exam Class II overhaul work are replacing boi tubes and refactory and retubing condens

> Class III Overhaul Work is defined as al the maintenance activity that is nonrecu in nature and cannot be anticipated unti unit is opened and inspected. Examples Class III overhaul work are replacing da turbine blading and repairing turbine-ge bearing surfaces.

No issue exists between Edison and the s number of overhauls to be performed. Edison and t only as to the amounts needed to cover Class III To develop the estimated expenses in 1983 for eac Class I and Class II overhaul activities, Edison specific work activities known to be required, an labor and material costs for each work activity.

Edison estimated Class III expenses for production units as the average of overhaul overr 1976 through 1980, adjusted for inflation. That categorized all historical budgeted costs as Clas expenses, and assigned all overruns to Class III. averaged 47% of the budgeted expenses.

The staff contends that the budgeting p and Class II overhaul expenses has changed. Edis major program to improve estimations of overhaul

developed improved procedures over the last two years. According to the staff, the utility is requesting (in constant 1981 dollars) some 16% more in overhaul expense ($2,918,000 versus $2,511,600) for just Class I and Class II costs than the average historical costs for all Class I, Class II, and Class III overhaul activities. Staff concludes that the estimates of 1983 Class I and Class II costs appear to make allowance for costs that were causing overruns in previous years.

Edison contends that staff overlooks basic factors which influence the level of overhaul expenses which will actually be experienced. Edison argues that no contingency amount is provided in Edison's estimates of Class I and Class II work to cover unforeseen or overrun expenses. Edison contends, therefore, that by relying on only Class I and Class II work, the staff has seriously underestimated the amount of the overhaul expenses Edison will actually incur.

The record shows that the aging of Edison's system has caused overhaul expenses to have an increasing characteristic. Edison asserts that the staff has failed to give this factor any weight in its estimates. However, we expect that Edison's budgeting process has already included increased age as an overhaul consideration.

In support of its showing on overhaul costs, Edison offered the results of two separate tests of the validity of its estimating methodology. The first test compares the results of Edison's and the staff methods with recorded expense incurred in 1981. According to this test, the staff method would underestimate recorded 1981 overhaul expenses by 13%. The Edison method, which includes Class III activities, overestimates recorded experience by only 1.4%.

Edison's second test to demonstrate the reasonableness of its test year figure for overhaul costs consisted of estimating Class I and Class II expenses by trending and then checking the statistical validity of the results. The trend using recorded 1976 through 1980 data yielded an estimate of $3.09 million per overhaul,

greater than the $2.92 million per overhaul requested. The statistical values for measuring the validity of the trend were good. Although Edison did not use this approach to estimate Class I and Class II overhaul expenses, Edison asserts that the method does provide an independent check of the reasonableness of Edison's estimate.

After careful consideration, we conclude that the truth lies somewhere between Edison's and staff's positions. We note that Edison characterizes all historic overruns as Class III expenses. Overruns can be caused by factors such as inflation higher than expected and poor cost estimates in addition to the unpredictable component which Edison defines as Class III work. Edison's improved budgeting efforts should allow greater accuracy in forecasting Class I and Class II expenses and a resulting reduction in the historically high overruns. However, even the most stringent budgeting process would fail to eliminate the need for a Class III budget category.

In giving weight to the above considerations, we have included, as reasonable for test year overhaul steam production expenses, $401,500 per overhaul for Class III expenses, or one-half of the Class III estimate requested, and all of the requested Class I and Class II costs. We believe that this significant increase of 32% per overhaul in constant dollars will provide Edison adequate funding for its overhaul activities on steam generation equipment.

F. <u>Hydraulic Power Generation Expenses</u>

1. <u>General</u>

Estimated hydraulic power generation expenses for the 1983 and 1984 years also exhibit larger increases than can be explained entirely by inflation and average growth patterns over recorded years 1976 through 1980. Edison attributes the higher level of expenses to significantly increased maintenance activities planned for 1983 and 1984.

Major repairs will be required on Vermillion Dam in estimated years 1983 and 1984 in the amount of approximately

$1 million for each year. There are additional maintenance activities planned for hydraulic production in the years 1983 and 1984 which total approximately $667,000 in 1983 and $1,650,000 in 1984. Edison states that these expenditures will be necessary to ensure reliability of hydraulic production facilities. Staff included this expenditure in its estimates.

2. Amounts at Issue

Table IV-6 shows that the differences between Edison and the staff all concern either trending or escalation. In total, Edison's estimate of test year 1983 hydraulic generation expenses exceeds the staff by about $500,000. Adopted amounts by account are shown in Table IV-7. As discussed elsewhere, we deny recovery of Edison's requested deferred maintenance expenses.

TABLE IV-6

HYDRAULIC POWER GENERATION EXPENSE
(Test Year 1983)

	System Estimates		
Item	Edison $M	Staff $M	Adopted $M
Trending	10,309	10,143	10,143
Escalation	2,024	1,727	1,576
Deferred Maintenance	351	351	-
Uncontested	2,005	2,005	2,005
Total	14,689	14,226	13,724

TABLE IV-7

HYDRAULIC POWER GENERATION EXPENSES
(Test Year 1983)

Account	Item	Edison $M	Staff $M	Adopted $M
	Operation			
535	Supervision and Engineering	1,604	1,668	1,661
536	Water for Power	505	601	592
537	Hydraulic Expense	1,297	1,192	1,141
538	Electric Expense	1,430	1,374	1,367
539	Misc. Hydro Power Gen. Expense	1,407	1,385	1,376
540	Rents	142	193	190
	Subtotal	6,385	6,413	6,327
	Maintenance			
541	Supervision and Engineering	831	814	808
542	Structures Exp.	1,164	1,143	1,076
543	Reservoirs, Dams, and Waterways	2,495	2,486	2,220
544	Electric Plant Expense	2,182	1,842	1,795
545	Misc. Hydraulic Plant	1,633	1,528	1,498
	Subtotal	8,305	7,813	7,397
	Total	14,690	14,226	13,724

G. Other Power Generation Expenses - Excluding Fuel

1. General

Other power generation expenses cover costs for all generating units other than hydraulic units and fossil- and nuclear-powered steam units. These expenses include the operation and maintenance of Edison's combined-cycle units, gas turbines, diesel generators, two wind generation units which are scheduled for commercial operation beginning in 1983, and Edison's geothermal power generation equipment.

As is the case for the other power production expense groups, the estimated expenses for the majority of other power

generation accounts in 1981 through 1984 exhibit significant real increases over the five-year recorded period 1976-1980.

Edison states that the addition of new other generation resources after 1976 has caused a significant increase in future years' O&M expenses. Beginning in 1977, Long Beach combined-cycle Units 8 and 9 were placed into commercial operation, followed by Cool Water combined-cycle Units 3 and 4 in 1978, and the Yuma Axis peaker in 1979. Commercial operation of the Alvawt and Schachle wind generation units is scheduled for 1983. The Brawley and Salton Sea geothermal units are scheduled for 1984.

Edison states that substantial anticipated increases in overhaul activity also contribute to the rise in other power generation expenses. Edison attributes this rise in projected overhaul activity primarily to the need for accomplishing first-time overhauls on the new Long Beach and Cool Water combined-cycle units and for performing expander-turbine overhauls on the Alamitos, Etiwanda, and Huntington Beach peakers.

Edison's estimates for research, development and demonstration (RD&D) expenses charged to other power generation expense accounts are significantly higher because of the increased regulatory and management emphasis on these activities. The staff has reviewed these increased levels of activity and does not take exception to them. The adopted amounts for RD&D and deferred maintenance are consistent with discussions elsewhere in this decision.

2. Amounts at Issue

The total amount of other generation expenses by which Edison's estimate exceeds staff's estimate in test year 1983 is $11.9 million. Details of this difference are presented by item in Table IV-8. Adopted amounts by account are shown in Table IV-9. The adopted amounts for RD&D and deferred maintenance are consistent with discussions elsewhere in this decision.

TABLE IV-8

OTHER POWER GENERATION EXPENSES - EXCLUDING FUEL
(Test Year 1983)

Item	System Estimates Edison $M	Staff $M	Adopted $M
Class III Overhauls	4,040	-	2,020
Fuel-Cell Write-Off*	3,854	2,381	3,438
Combined Cycle	7,708	6,033	7,708
Trending	2,605	2,710	2,710
Escalation	3,673	2,254	2,283
RD&D	7,000	7,000	5,250
Deferred Maintenance	763	763	-
Uncontested	4,383	4,383	4,383
Total	34,026	25,524	27,792

*Expenses for Fuel-Cell Write-Off are shown in 1983 dollars.

TABLE IV-9

OTHER POWER GENERATION - EXCLUDING FUEL
(Test Year 1983)

Account	Item	Edison $M	Staff $M	Adopted $M
	Operation			
546	Supervision and Engineering	928	951	916
548	Generation Expense	4,193	2,357	3,820
549	Misc. Other Power Gen. Exp.	10,875	9,327	8,419
550	Rents	18	18	18
	Subtotal	16,014	12,653	13,173
	Maintenance			
551	Supervision and Engineering	1,019	946	935
552	Structure Expense	903	430	854
553	Generating and Plant Expense	15,463	10,913	12,234
554	Misc. Other Exp.	629	582	596
	Subtotal	18,014	12,871	14,619
	Total	34,028	25,524	27,792

3. Class III Overhaul Expenses

Edison used a methodology to estimate overhaul expenses for other power generation accounts similar to the one used for the steam power generation accounts. Specific Class I and Class II activities were identified and budgeted. However, since there is inadequate historical data regarding overhaul costs for these units, an overrun analysis could not be used to estimate Class III costs. Instead, Edison calculated that the average historical overrun (Class III) costs for steam generation overhauls had been 47% of the amounts budgeted. Edison then assumed that other power generation overhauls would experience the same magnitude of overruns. Thus, Class III projections were set at 47% of Class I and Class II projections.

The staff, on the other hand, again excluded any allowance for Class III overhaul activities from its estimate of other power generation production overhaul expenses. Staff additionally questioned whether the cost overruns on the newer gas turbines and combined cycle plants in this category would be comparable to the overruns for the older coal and oil/gas-fired steam plants.

As we discussed elsewhere in this opinion, we believe that Edison's revised budgeting process will lessen but not eliminate Class III overhaul costs. Accordingly, we are adopting one-half of Edison's estimate of expenses for test year Class III overhaul activities.

4. Combined-Cycle O&M Expenses

The staff recommends that O&M expenses (excluding overhaul expenses) of combined-cycle generation equipment be set at the level of average 1979 and 1980 expenses. In the staff's opinion, this provides a reasonable estimate of normalized test year expenses (on a constant 1981 dollar basis). Edison contends that the staff's approach underestimates the O&M expenses that the utility is likely to incur in test year 1983 for its combined-cycle units.

Edison believes that the years 1979 and 1980 are not representative of normal O&M expenses for its combined-cycle units. Edison points out that the Long Beach combined-cycle unit began

operation in 1977 and the Cool Water combined-cycle unit began in 1978. During the first years of operation, according to Edison, units such as Long Beach and Cool Water go through a so-called immaturity period, which means that certain difficulties must be worked out before the unit achieves its full potential and attains its normal level of operating costs. For most conventional units, this period may be one or two years; however, in the case of the Long Beach and Cool Water combined-cycle units, Edison reports that the immaturity period lasted through 1980. Edison provided supporting data on the capacity factors and forced-outage rates for these units, and according to these data, the first year approaching normal operation was 1981. Edison argues that, by using only 1979 and 1980 recorded data, the staff has underestimated normal O&M expenses for the Long Beach and Cool Water combined-cycle units. Edison offers the data shown in Table IV-10 to illustrate that the staff's estimate for 1983 would be less than recorded 1981 expenses and would seriously underestimate the level of expenses that the utility expects to incur in the test year 1983.

TABLE IV-10

COMPARISON OF ESTIMATES OF
O&M EXPENSES FOR COMBINED-CYCLE UNITS

(Thousands of 1981 Dollars)

Year	Edison Estimate	Staff Estimate	Recorded
1981	5,592	6,033	6,342
1982	7,707	6,033	N/A

Edison states that its estimate of 1983 O&M expenses for Long Beach and Cool Water is higher on a constant-dollar basis than the recorded amount for 1981 because there are a significant number of special maintenance activities and higher operation expenses anticipated in 1983 compared with the recorded 1981 experience. These maintenance activities were not performed in either the recorded 1979-1980 period used by the staff or in the year 1981. According to the

record, the staff did not analyze Edison's workpapers to see if any special maintenance activities were scheduled to be performed in 1983. Edison contends, therefore, that the staff's estimate of combined cycle O&M expenses is unreasonably low and that its own estimate is supported by a detailed analysis of the expenses that will be incurred in 1983.

We are convinced by Edison's rationale, and we will adopt Edison's test year estimate of O&M expenses for combined-cycle generating units.

5. Fuel Cell Amortization

Edison included $7.7 million in its 1983 funding request to amortize capital expenditures made on its fuel cell program. These expenditures were made in support of research and development expected to culminate in 15 commercially available 26 MW fuel cells. This project was begun in 1973. Edison expected to receive credit for its RD&D contribution against the ultimate price of the fuel cells. The expenses were placed in a holding account accruing AFUDC since Edison intended to capitalize them as part of the commercial cost of the fuel cells. In this case Edison has requested recovery of the amount since development efforts have been abandoned. The total amount Edison proposed to recover over a two-year period is $15,415,000 of which $4,964,000 is accumulated AFUDC.

The staff, after reviewing the problems associated with a large fuel cell unit, agreed that it is appropriate to abandon the original program. However, the staff noted that the program has lain dormant for over two years; "the only charges to the fuel cell [program] since the start of 1979 have been AFUDC." (Exh. 40 at p. 3-1.) The staff recommended that Edison be allowed only recovery of the non-AFUDC portion of the fuel cell expenditures and that the amortization period be four years rather than two years. Edison stipulated to the staff's proposal for a four-year amortization period at the oral argument.

The question before us then is whether Edison should recover its expenses for the abandoned fuel cell program and whether it should also recover AFUDC on those expenditures. In D.90404 at pp. 18-20a and D.92497 at pp. 77-84, we stated a standard for determining whether this Commission should permit the recovery of costs sunk in a project upon abandonment. The standard addresses the prudency of management decisions regarding initially whether to proceed with a given project and whether to abandon it at some subsequent time. The company must also demonstrate that all expenditures made in pursuing such a project were reasonably incurred. We further note that in each aforementioned decision where we applied this standard, we disallowed recovery of AFUDC.

We see nothing in the record which demonstrates Edison acted imprudently in supporting research and development of fuel cells, particularly in light of the concerns expressed by this Commission in the 1970s regarding California's declining environmental quality and lack of energy efficiency combined with a heavy reliance on traditional gas- and oil-fired power plants. We take note that our staff has reviewed Edison's reasons for abandoning this fuel cell project and has concurred with the company's decision. We therefore consider Edison's recovery of its actual expenditures to be appropriate.

We now turn to the question of Edison's recovery of AFUDC. As noted above, we have not allowed recovery of AFUDC on abandoned commercial projects, permitting recovery of those accruals only for plant placed in rate base as "used and useful." We continue to support this existing policy for commercial projects; however, we recognize that research and development of new energy technologies are in themselves more risky than normal utility activities. If compensation of AFUDC on abandoned RD&D projects is categorically disallowed, then we may stifle all company interest in risking stockholder money in pursuit of those projects. On the other hand,

recovery of accumulated AFUDC must occur only after the project has been extensively scrutinized since in no way should Edison consider allowance of AFUDC for some RD&D projects to be an indication of our willingness to underwrite all such projects no matter how poorly managed.

As we discussed above, we find Edison's decisions to pursue and subsequently abandon its fuel cell project to be reasonable and prudent. However, we take issue with Edison's decision to wait until this rate case to request amortization of project expenses. Since the last direct charges to the project were made at the start of 1979, the company had plenty of time to determine that the program should be abandoned and reflect that determination in its 1981 Test Year rate request. Failing to move to a decision about the project with reasonable speed does not constitute good management practice. Therefore, we will allow Edison to recover only AFUDC accumulated through the end of 1980.

We take notice at this juncture of the Form 1 filing made by Edison for the year ending December 31, 1980. The Construction Work in Progress accounts at page 406 and following include an entry for the "Pratt and Whitney Aircraft--Development of Substation-Sized Fuel Cell Generating Unit" in the amount of $13,751,684 (at p. 406-L). Edison may recover this amount over the four-year amortization period to which the company stipulated. The 1983 test year portion of this amortization amounts to $3,437,921.

H. Nuclear Generation
<u>Expenses - Excluding Fuel</u>

1. <u>General</u>

The nuclear generation expense group of accounts includes all O&M expenses, other than fuel expense, associated with Edison's 80% share of SONGS Unit 1. Edison estimates these expenses to total $33,099,000 in 1983.

Edison's share of prudent costs for SONGS Units 2 and 3 and Palo Verde Units 1 and 2 will be recoverable through separate offset proceedings which will coincide with the firm operation dates of these units.

2. Amounts at Issue

Edison's estimate of nuclear power production expense is approximately $5.4 million less than the staff's. Table IV-11 provides details of the difference between Edison and the staff. Beside escalation and trending differences, the only differences between staff and Edison recommendations are due to treatment of SONGS Unit 1 sleeving cost. While Edison and staff agreed on RD&D expenditures, we adopt a smaller amount, as discussed in Section V. Adopted amounts by account are shown in Table IV-12.

TABLE IV-11

NUCLEAR POWER GENERATION EXPENSES - EXCLUDING FUEL
(Test Year 1983)

Item	System Estimates		
	Edison $M	Staff $M	Adopted $M
Unit 1 Sleeving	-	6,500	14,158
Trending	14,303	14,095	14,095
Escalation	4,515	3,699	3,373
RD&D	750	750	468
Uncontested	13,531	13,531	13,531
Total	33,099	38,575	45,625

TABLE IV-12

NUCLEAR POWER GENERATION - EXCLUDING FUEL
(Test Year 1983)

Account	Item	Edison $M	Staff $M	Adopted $M
	Operation			
517	Supervision and Engineering	3,992	3,594	3,570
519	Coolants & Water	514	475	472
520	Steam Expense	5,397	5,261	5,212
523	Electric Expense	175	171	170
524	Misc. Nuclear Power Expenses	11,799	17,918	21,563
525	Rents	24	27	26
	Subtotal	21,901	27,446	34,613
	Maintenance			
528	Supervision and Engineering	3,104	2,717	2,699
529	Structure Expense	967	944	934
530	Reactor Plant Equipment	2,735	3,100	3,061
531	Electric Plant	3,760	3,689	3,646
532	Misc. Nuclear Power Expenses	696	679	672
	Subtotal	11,262	11,129	11,012
	Total	33,099	38,575	45,625

3. SONGS Unit 1 Sleeving

a. Degradation of Steam Generator Tubes

The physical problem underlying the sleeving issue came to light during an outage for refueling in the spring of 1980 when it was discovered that a considerable number of the tubes in the steam generators had sustained degradation from intergranular attack (IGA) on their outer surfaces from corrosive elements in the steam. To restore SONGS Unit 1 to service, Edison had to choose one of three possible courses of action: plugging the damaged tubes, replacing the steam generators, or sleeving the tubes.

Edison rejected tube plugging because the power output of SONGS Unit 1 would have been drastically reduced since a significant portion of the tubes was damaged. The utility rejected replacement of the steam generators because it would have required an extended period of outage, as well as entailing higher capital costs and increased replacement fuel costs. Edison selected sleeving as its most reasonable option.

The sleeving project cost $70.8 million, with Edison bearing 80% or about $56.6 million. The remaining 20% is borne by SDG&E.

In D.93640 in A.60321 dated October 20, 1981 the Commission withheld final judgment regarding the reasonableness of Edison's actions with regard to SONGS Unit 1, and deferred the issue to this proceeding. Recovery of replacement fuel costs would be treated separately in an ECAC proceeding. In this proceeding, both staff and Edison have focused solely on recovery of the sleeving cost of SONGS Unit 1 and have not discussed how replacement fuel costs should be allocated.

b. Cost Recovery Issues

The staff agrees with Edison that the sleeving option chosen by Edison was the only reasonable choice and that the repair operation was done reasonably and prudently. Nevertheless, in his testimony, the staff engineer recommended that the amount of Edison's recovery in rates be limited to $26 million. The staff accountant accepted this amount and recommended that the $26 million be expensed over a four-year period rather than capitalized and included in rate base.

The staff's opening brief states:

> "The staff does not feel that the total cost of the resleeving project should be borne by the ratepayer - rather, it should be apportioned as set out above. The reason is that the injury that occurred at SONGS I was the result of a calculated design risk that

> simply did not pan out. The company should have to bear a large proportion of this risk which was built into the installation at the time it was designed."

The staff engineer gave the opinion that Westinghouse Electric Corporation (Westinghouse), the manufacturer of the equipment, was responsible for the degradation of the tubing in the steam generators because of its faulty design of the sludge removal system. He was cross-examined on the question of whether or not Westinghouse should share a part of the expense burden, and he replied that others had brought suit against Westinghouse for the identical problem and that Edison should consider suing as a means of recovering the disallowed portion of the sleeving cost. Specifically, staff cited complaints for damages brought by Virginia Electric Power Company, Florida Power and Light (FP&L), Wisconsin Electric, and Consumers Power Company in Michigan against suppliers of steam generators. Settlement was reached in all but the FP&L case which is still pending. The engineer went on to state that a report should be prepared which would analyze Edison's legal position and whether Edison could in good faith file a lawsuit, and that if the report showed that Edison could not in good faith file a lawsuit, the staff would recommend that the entire amount of the sleeving cost be capitalized and allowed in rates.

Edison engaged a legal expert who prepared and presented, as Exhibit 73, his opinion on the merits and likelihood of Edison's success in a lawsuit against Westinghouse. The thrust of the legal expert's opinion is that the probability of recovery from Westinghouse for the cost of restoring the steam generators (i.e. direct compensatory damages) would be less than one chance in 20,000. He testified that, in order to prevail in a suit for direct compensatory damages, Edison would have to succeed in a series of five separate and distinct legal steps, as follows:

1. Get by a demurrer.
2. Overcome a motion for summary judgment.
3. Get by the statute of limitations.
4. Win the trial on the merits.
5. Overcome all appeals.

In the opinion of the legal expert, there are two theories on which Edison could possibly proceed in an action against Westinghouse: (1) a breach of warranty or contract theory and (2) a negligence theory.

The staff contends that it is not at all certain, as Edison's expert concluded, that the utility has no chance of winning a lawsuit against Westinghouse. The staff asserts that given the success of other utilities in other states in what it calls identical suits, the reverse could be the case. Edison, on the other hand, asserts that actions by other utilities against Westinghouse are irrelevant unless the law in the other jurisdictions is the same as California law and the facts are related to the Unit 1 tube failure. Edison points out that the staff has provided no analysis or evidence of either the law or facts involved in the other litigation.

With respect to the negligence theory, the staff asserts that Edison's legal expert omitted from consideration the general rule that the statute of limitations in a negligence action does not begin to run until some damage has occurred. Applying that rule to this case, the staff points out it is not ascertainable when the corrosion of the tubes began and the necessary damages occurred. It is only certain that the damages happened some time prior to April 1980 when they were discovered; therefore, the statute of limitations should have begun to run at that point. Thus, the staff argues, Edison is not now foreclosed from an action against Westinghouse. Edison contends that to the extent the staff cites the law with respect to the statute of limitations for negligence actions, it is incorrectly relied upon and does not relate to the problems involved.

c. Adopted Sleeving Costs

The staff contends that a substantial portion of the expense associated with the repair of SONGS Unit 1 should be disallowed, based not on a specific allegation of imprudence on the part of Edison, but rather on an allocation of a calculated design risk between ratepayers and the utility. Absent a finding of imprudence or an incident of truly catastrophic magnitude, we consider such expenditures to be properly recoverable in full through the ratemaking process, subject to the normal constraints of test year ratemaking.

Traditionally, ratepayers have borne the risk that operative utility plant will fail to function properly during its expected life. Where unscheduled maintenance is required, ratepayers have borne the expense necessary to bring the plant back on line. Occasionally, unforeseen outages have led to a large repair expense which would have been burdensome on ratepayers if the expense were collected immediately in rates. In these circumstances, the expense has been amortized over a period of years to mitigate any undue adverse impact on ratepayers. Incidentally, it has also been traditional not to allow recovery of carrying costs arguably associated with the deferred recovery of amortized maintenance expense. This, in effect, constitutes a modest sharing of burdens by utility shareholders.

We find no basis in the record to conclude that Edison acted unreasonably in accepting what proved to be a faulty plant design or in its detection and repair of the steam generator failure which subsequently occurred. We are, however, uncertain whether Edison acted reasonably in possibly having failed to take timely legal action against Westinghouse. Even absent unreasonable conduct on Edison's part, it is conceivable that rate recovery of all or a part of the repair costs should be deferred, pending a determination of Edison's prospects of recovering such costs from Westinghouse.

Based on the showing, described above, by the staff and by a legal expert engaged by Edison, we find our record inadequate to determine whether Edison could successfully sue Westinghouse under any of the various legal theories discussed on that record. We share our staff's concern, however, as to the narrow range of potential legal options considered by Edison's witness.

We are not persuaded by Edison's argument that it is barred from recovering from Westinghouse by the running of the statute of limitations. Courts in California have held that for damage to real and personal property resulting from negligence, the statute of limitations begins to run when plaintiffs either (1) actually discover their injury and its negligent cause or (2) could have discovered injury and cause through the exercise of reasonable diligence. See Leaf v City of San Mateo (1980) 104 Cal App. 3d 398, and cases cited therein. Under this rule, the statute of limitations will not run out until April 1983, at the very earliest.

Nor are we convinced by Edison's argument that an action against Westinghouse would be futile. Based on the record before us, it is uncertain whether Westinghouse should have foreseen the problems caused by IGA and/or the buildup of sludge and, if so, whether Westinghouse took all reasonable steps to prevent these problems. Our record shows that four other electric utilities, similarly situated to Edison, have brought suit against suppliers of steam generators. Three of these companies have achieved some level of compensation through settlement. The fourth lawsuit has not been resolved. In contrast, Edison has not filed suit.

We are concerned that Edison's evaluation of and action on its legal options in the present circumstances may not match what would be expected of an unregulated business corporation, faced with a similar extraordinary operational failure but without the financial backstop of utility ratepayers. Edison has hired counsel to testify before this Commission as to a variety of reasons why a successful

suit is unlikely. A major risk averted to is that the statute of limitations may already have run on any claim Edison may have had. The record also suggests, however, that the statute of limitations may still be running and, in fact, may shortly be running out. In addition, retaining counsel to impugn its own litigation prospects on an official hearing record could prove harmful to the interests of Edison and its ratepayers.

For these reasons we are not satisfied that Edison has acted prudently in evaluating and pursuing its legal options in relation to Westinghouse's potential liability. On the other hand, we cannot say that Edison has been imprudent; nor do we wish to induce this or any utility to pursue frivolous or pointless litigation. Therefore, we will not, at this time, disallow recovery of any portion of the SONGS Unit 1 sleeving expense. We will, however, retain the ability and the option to disallow an appropriate share of such expense, if warranted, at a later date, and we will secure the means to complete the necessary evaluation.

We make no decision as to whether replacement fuel costs during the 13-month period when SONGS Unit 1 was inoperative should be allocated similarly. We will address this issue in an appropriate ECAC proceeding.

d. Ratemaking Treatment

The dispute between staff and Edison regarding recovery of the allowed sleeving cost centers on the application of general accounting principles and the interpretation of the Uniform System of Accounts (USA) established by the FERC and adopted by this Commission.

Staff contends that the sleeving constituted a repair which restored the serviceability and maintained the life of the steam generator. Staff points out that SONGS Unit 1 has not been operating at full capacity since it has been brought back on line. Consequently, the sleeving cannot be considered to have enhanced or added to the plant's operating life.

Staff would treat the sleeving cost as extraordinary maintenance expense which would be amortized over a four-year period. This treatment, of course, would disallow recovery of all AFUDC for ratemaking purposes.

Edison requests capitalization of the sleeving cost which would be ultimately transferred to plant in service. As plant in service, this cost would be depreciated over the remaining useful life of SONGS Unit 1. Edison states that its request to capitalize the sleeving cost was based on its opinion that the work constitutes a substantial addition to property of minor items which did not previously exist.[6] Under Edison's interpretation of the USA, the sleeving addition was substantial in both the physical and monetary sense. In physical terms, sleeves were added to 6,500 of the steam generator tubes. This equals 57% of all the tubes and 93% of the tubes in which sleeving was possible. In economic terms the cost of sleeving amounted to $70.8 million compared to the original cost of the steam generators of about $7 million.

We are of the opinion that the sleeving addition constituted maintenance as defined in the USA as including "work performed specifically for the purpose of preventing failure, restoring serviceability, or maintaining life of plant." We have difficulty concluding that the sleeving is a capital asset when it did not extend the useful life, operating capacity or efficiency of the steam generator. As noted previously, the facility has been operating at reduced capacity since the sleeving repair was made. We therefore, will treat the sleeving cost as a maintenance expense and adopt the staff recommended four-year amortization.

---

[6] The USA in its Electric Plan Instruction provides that: "When a minor item of property which did not previously exist is added to plant, the cost thereof shall be accounted for in the same manner as for the addition of a retirement unit, as set forth in paragraph B(1), above, if a substantial addition results, otherwise the charge will be to the appropriate maintenance expense account."

e. Further Evaluation of Litigation Prospects

Our decision to allow Edison to begin recovery of its sleeving costs comes only after much deliberation. Although we have not adopted a risk allocation theory in this instance we believe that a case can be made that, in terms of risk allocation, shareholders should not necessarily be immune from the costs of an extraordinary occurrence such as the one at SONGS Unit 1 even if imprudence has not been shown. Our decision does not foreclose us from adopting a risk allocation theory in a future proceeding.

Further, we have seriously considered disallowing half of the sleeving costs, for the reason that Edison has not finally persuaded us that it has acted prudently in failing to pursue its legal remedies against Westinghouse. As noted above, we are not persuaded that the legal expert retained by Edison has thoroughly evaluated the utility's prospects for successful litigation against Westinghouse. Although we are allowing recovery to begin, we also intend to examine further whether Edison has adequately pursued its remedies against Westinghouse and whether such remedies should be pursued further. We specifically place Edison on notice that: first, we are today directing our General Counsel to examine what legal remedies Edison has had or does now have against Westinghouse to recover all or part of the costs associated with the sleeving of SONGS Unit 1; second, if we conclude that Edison should pursue its present legal remedies against Westinghouse, Edison will be expected to do so; and third, if Edison has failed in the past or fails in the future to pursue those remedies with adequate vigor, we will disallow an appropriate amount of the sleeving costs.

We will make the final three years of sleeving costs recovery subject to refund in order to preserve the possibility of disallowance if that proves necessary. If warranted by the results of our General Counsel's analysis, such a disallowance might appropriately be proposed and acted upon in conjunction with the

attrition adjustment to take effect in January 1984, or in the context of Edison's rate case for test year 1985. In any event, it is reasonable to permit Edison to recover the first of four years' amortization amounts, through rates for the 1983 test year.

The essence of our decision is that Edison has made a prima facie showing regarding its election not to institute legal proceedings against Westinghouse, but we have yet to reach a final determination regarding the reasonableness of Edison's actions. We direct our General Counsel to examine the facts and law applicable to the situation at issue, as well as the circumstances in other jurisdictions where utilities have successfully pursued actions against Westinghouse and to determine, based on an independent view of the facts and the law, whether Edison has and should pursue (or had and should have pursued) legal remedies against Westinghouse.

I. Power Generation Expenses (Non-ECAC Fuel Related)

1. General

Non-ECAC fuel related expenses include costs of coal station ash handling, coal weighing, and gas facilities; fuel administration, transportation, and analysis; and the ultimate disposition of spent nuclear fuel.

The $1.0 million total difference between Edison and the staff estimates of non-ECAC fuel related power generation expenses results solely from differences in their respective rates of escalation. Table IV-13 provides details of the differences between Edison and the staff.

TABLE IV-13

POWER PRODUCTION EXPENSES (NON-ECAC FUEL RELATED)
(Test Year 1983)

Item	System Estimates Edison $M	Staff $M	Adopted $M
Spent Fuel	8,757	8,197	-*
Other	37,155	36,758	36,632
Total	45,912	44,955	36,632

*Adopted amount of $8,085,000 is included net of tax in summary of earnings.

2. Spent Nuclear Fuel Disposal Costs

On December 5, 1980, we provided in our generic ECAC proceeding that the utilities and staff should address the issue of nuclear fuel disposal costs in pending general rate cases (OII 56, D.92496). In our general rate case decision for Edison later that month, we ordered Edison to prepare a study to assess the various cost and ratemaking aspects of nuclear fuel disposal (D.92549, December 30, 1980). Edison submitted its report in May 1981, and has requested a ratemaking treatment for its projected costs of nuclear fuel disposal from SONGS Unit 1 in this proceeding.

When nuclear fuel is discharged from a reactor, the highly radioactive "spent nuclear fuel" is placed in a spent fuel storage pool, usually at the site of the reactor. However, the storage pools are not intended, nor are they designed, to be the ultimate repository of the spent nuclear fuel. There are two possible options for the ultimate disposition of the spent nuclear fuel: reprocessing or permanent disposal. Although Edison interpreted the term "disposal costs" as used in D.92549 to refer to reprocessing only, we intended that the term refer to either reprocessing or permanent disposal.

Edison proposed that the CPUC allow current recovery in base rates of its projected expenses associated with permanent disposal of spent nuclear fuel. The revenue requirement in any year would be determined by using a straight-line method of recovery based on the remaining life of the nuclear plant. Edison's basis for assuming that permanent disposal will occur rather than reprocessing was the indefinite ban on reprocessing that former President Carter imposed on April 7, 1977. Even though the current administration has lifted the ban on reprocessing, the ultimate method of treatment to be adopted is not known. However, Edison considers its projections of permanent disposal costs to be a reasonable estimate of reprocessing costs as well.

The staff presented its views on the recovery of spent nuclear fuel costs in its report (Exhibit 120) and in testimony (Exhibit 27 and Exhibit 121). In general, the staff agrees with Edison on the use of the straight-line method of recovery. Moreover, the staff believes that Edison's cost estimates are reasonable even if reprocessing is ultimately used.

Staff proposed that Edison be required to identify the accrual and rate base components of recovered disposal costs as line items in its Summary of Earnings, rather than including these items only in fuel expense and rate base totals, respectively. We agree, and will also require Edison to provide cumulative and yearly accrual and rate base information in future rate proceedings in a form comparable to Attachment 1 to Exhibit 121.

Although staff and Edison agreed regarding basic cost projections and the recovery method, they disagreed regarding ratemaking treatment of taxes on the recovered disposal costs. The ratemaking treatment of taxes in turn affects the rate base component. Since the treatment of taxes is an integral part of our adopted method for recovery of spent nuclear fuel disposal costs, we will discuss such treatment in this section.

Staff's revenue adjustment for the recovery of spent nuclear fuel costs is net instead of gross of tax. Staff contends that this approach provides a more equitable cost recovery from the ratepayer because it matches the benefits of nuclear power with the costs of nuclear fuel disposal. Under Edison's method, Edison essentially would collect double the amount allowed to be accrued for the eventual cost of treatment and would then refund the tax deductions realized when the disposal costs are actually incurred.

Staff points out that the ratepayer would be at risk using Edison's cost recovery approach if future tax reductions were enacted. Under the staff method, tax changes would be compensated for under staff's proposed memorandum tax reserve.

Edison claims that the staff approach has the effect of treating spent nuclear fuel costs as if they were currently deductible for tax purposes, which they are not. In Edison's view this is a form of negative normalization, i.e. treating an expense as an income tax deduction for ratemaking purposes prior to the time that it is allowed to be deducted for income tax purposes.

We find staff's arguments persuasive, and adopt the staff approach which results in a reduction in net operating revenues of $3,957,000 and in a $1,978,000 lower rate base in the summary of earnings.

J. Transmission Expenses

Edison's estimate of transmission expenses exceeds the staff's estimate by approximately $1.6 million. Table IV-14 provides details of the amounts at issue between Edison and the staff, all of which relate to trending and escalation. We do not approve Edison's request for deferred maintenance, as discussed elsewhere.

TABLE IV-14

TRANSMISSION EXPENSE

(Test Year 1983)

Item	System Estimates		
	Edison $M	Staff $M	Adopted $M
Trending	36,883	35,973	35,973
Escalation	6,521	5,812	5,434
Deferred Maintenance	306	306	-
Uncontested	12,302	12,302	12,302
Total	56,712	55,093	54,029

Table IV-15 shows a comparison of the estimation of transmission expenses by accounts, together with the amounts we are adopting for the test year.

TABLE IV-15

TRANSMISSION EXPENSES

(Test Year 1983)

Account	Item	Edison $M	Staff $M	Adopted $M
	Operation			
560	Supervision and Engineering	5,934	6,253	6,216
561	Load Dispatching	2,858	2,942	2,933
562	Station Expense	13,411	12,768	12,710
563	Overhead Line Expense	935	863	858
564	Underground Line Expense	41	40	40
565	Transmission of Electricity by Others	8,189	8,189	8,189
566	Misc. Transmission Expenses	2,499	2,139	1,742
567	Rents	1,610	1,742	1,717
	Total Oper. Expense	35,477	34,936	34,405
	Maintenance			
568	Supervision and Engineering	1,901	1,666	1,657
569	Structures	1,278	1,241	1,113
570	Station Equipment	6,948	6,699	6,522
571	Overhead Lines	7,209	7,057	6,883
572	Underground Lines	66	65	64
573	Misc. Transmission Plant	3,833	3,430	3,385
	Total Maint. Expense	21,235	20,158	19,624
	Total Trans. Expense	56,712	55,094	54,029

K. Distribution Expenses

The amounts at issue between Edison's and the staff's estimates of distribution expenses total approximately $2.6 million. As shown in Table IV-16, this difference relates entirely to escalation. We approve expenses for RD&D and disapprove the requested deferred maintenance, as discussed elsewhere.

TABLE IV-16

DISTRIBUTION EXPENSES
(Test Year 1983)

Item	Edison $M	Staff $M	Adopted $M
	System Estimates		
Escalation	19,747	17,109	15,979
RD&D	100	100	80
Deferred Maintenance	124	124	-
Uncontested	122,933	122,933	122,933
Total	142,904	140,266	138,922

Table IV-17 presents a comparison by FERC account of Edison's and the staff's estimates for distribution expenses, together with the amounts we are adopting for the test year.

TABLE IV-17

DISTRIBUTION EXPENSES
(Test Year 1983)

Account	Item	Edison $M	Staff $M	Adopted $M
	Operation			
580	Supervision and Engineering	13,983	13,856	13,802
582	Station Expense	8,060	7,979	7,945
583	Overhead Line Exp.	7,492	7,356	7,298
584	Underground Line Expense	1,772	1,748	1,738
585	Street Lighting Expense	7,834	7,603	7,505
586	Meter Expense	10,859	10,771	10,733
587	Cust. Install Expense	7,776	7,693	7,657
588	Misc. Distrib. Expenses	10,176	10,027	9,944
589	Rents	495	479	473
	Total Op. Expenses	68,447	67,512	67,095
	Maintenance			
590	Supervision and Engineering	10,142	10,038	9,994
591	Structure Expense	3,613	3,503	3,457
592	Station Equipment Expense	3,132	3,075	2,914
593	Overhead Line Exp.	25,423	24,823	24,569
594	Underground Line Expense	8,017	7,854	7,785
595	Line Transformer Expense	4,785	4,672	4,625
596	Street Lighting Expense	2,540	2,490	2,468
597	Meter Expense	2,380	2,333	2,313
598	Misc. Distrib. Plant Expense	14,424	13,965	13,772
	Total Maint. Expense	74,456	72,753	71,897
	Total Dist. Expense	142,903	140,265	138,992

L. Customer Accounts Expense

Amounts at issue between Edison and the staff for customer accounts expenses total approximately $5.5 million. The details of this difference are shown in Table IV-18. Table IV-19 presents a comparison by FERC account.

TABLE IV-18

CUSTOMER ACCOUNTS EXPENSES*
(Test Year 1983)

Item	System Estimates Edison $M	Staff $M	Adopted $M
Customer Service Representatives	1,155	-	1,155
Trending			
Account 903	33,379	30,848	30,356
Account 905	2,378	2,159	2,137
Escalation	9,474	7,922	7,650
Uncontested	24,233	24,233	24,233
Total	70,619	65,162	65,531

*Excludes Account 904, Uncollectibles.

TABLE IV-19

CUSTOMER ACCOUNTS EXPENSES

(Test Year 1983)

Account	Item	Edison $M	Staff $M	Adopted $M
	At Present Rates			
901	Supervision	3,318	3,266	3,244
902	Meter Reading Expenses	18,009	17,818	17,736
903	Customer Records Expense	46,538	41,627	42,146
904	Uncollectible Accounts	3,322	3,322	3,322
905	Misc. Customer Accounts Exp.	2,755	2,451	2,405
	Total	73,942	68,484	68,853
	At Proposed Rates			
904	Uncollectible Accounts	6,096	6,096	4,501*
	Total Customer Account Expense	80,038	71,258	73,354

*At adopted rates.

The staff made various recommendations regarding Edison's energy theft program. We believe that this program is a worthwhile effort, and in the next general rate proceeding, we will expect Edison to submit a report detailing the progress, costs, accomplishments, and plans for this program.

1. Customer Service Representatives

The staff recommends that we disallow approximately $1.2 million which Edison has included in its estimate of the labor component of Account 903 for additional customer service representatives. The staff contends that: (a) the need for the additional customer service representatives has not been adequately supported; (b) the number of billing inquiries should drop as customers get used to monthly billing; and (c) customers would prefer

foregoing faster response to their calls as an alternative to paying for the additional representatives.

In support of its position, Edison presented a study showing that, for the period 1979 through 1981, the following increases developed in workload for customer service representatives: (a) incoming calls were up 11%; (b) billing inquiries increased by 59%; (c) the amount of correspondence processed was up 29%; and (d) the processing of customer accounting orders was up 10%.

This increase in workload was accompanied by a 17% decrease in the number of customer service representatives. Edison states that the handling of an increased workload by a smaller work force has reduced the quality of service it provides its customers. Edison reports that the number of calls lost because of customers hanging up because of delayed answering by overloaded representatives increased over a two-year period by 55%, from 361,817 in 1979 to 559,637 in 1981, representing an increase in the percent calls lost from 8.9% in 1979 to 12.4% in 1981. In Edison's opinion, this indicates that there is an unacceptably high number of dissatisfied customers. Edison asserts that the number of lost calls would have been even greater had it not concurrently reduced the number of incoming telephone lines from 339 to 291.

In response to the staff's contention that inquiries will decrease as customers get used to monthly billing, Edison points out that monthly billing was instituted in April 1980; that customers had from 12 to 20 months of experience with monthly billing by the end of 1981; but that customer billing inquiries in the first two months of 1982 increased by 66% over the prior year.

The complaints of a number of customers at the hearings we held in this proceeding for receipt of public witness testimony give credence to Edison's position. We are of the opinion, based on this record, that the level of service Edison is providing for processing incoming customers service calls is not adequate. We are not

convinced by the staff's argument that customers would forego shorter response times in exchange for lower bills. We believe that Edison's request is fully justified. Accordingly, we will adopt Edison's estimate for the increased cost of customer service representatives.

2. Return Postage Envelopes

Edison included approximately $8 million in the revenue requirement requested in the application to cover prepaid return envelopes to facilitate payment of bills by its electric customers. This item was not opposed by the staff.

At the oral argument on August 12, 1982, Edison made the following statement:

> "We included $8 million in our request to cover pre-paid postage envelopes as a convenience for our customers. Due to a number of considerations, including the current economic conditions, we feel this item should be withdrawn."

As a consequence, we will not include any amount in the adopted revenue requirement for this item of postage expense.

3. Trending

The staff did not accept Edison's estimates of nonlabor expenses of $14,446,000 for Account 903 and $1,401,000 for Account 905 due to lack of statistical significance. Staff used other econometric modeling techniques to obtain its estimates of these costs.

For nonlabor portion of Account 903, Customer Records and Collection Expenses, staff based its estimate of $11,915,000 on a high historical correlation of the average price of energy to residential customers and the total number of customers with the nonlabor expenses in that account. From our review of this issue, we conclude that the staff has departed from the principles of econometric modeling in relying on an unmeaningful relationship, i.e., a negative correlation between energy prices and nonlabor expenses in Account 903.

The staff tested historical correlations between the nonlabor component of Account 905, Miscellaneous Customer Accounts Expenses, and expenses in a number of other accounts, and then estimated expenses in this category to be $1,182,000 based on a high historical correlation which it discovered between this category and supervisory labor expenses. The staff has again departed from the principles of good econometric modeling in assuming that there must be a causal and thus predictive relationship between two factors because of a high historical correlation. We find no basis for hypothesizing such a relationship.

Since neither the estimates of Edison nor those of staff are acceptable, we have adopted a method which recognizes the average historical cost per customer, and have estimated the nonlabor expense as $12,582,000 for the nonlabor component of Account 903, and $1,160,000 for the nonlabor component of Account 905. We note that these estimates are in 1981 dollars; the escalation rates adopted in Section IV.C must be applied to obtain total 1983 revenue requirements.

M. Customer Service and Informational Expenses

This group of accounts includes the expenses of the conservation, load management, and cogeneration programs. Edison's estimate of Customer Service and Information Expenses exceeds the staff's estimate by approximately $31.0 million. Table IV-20 shows details of the amounts at issue between Edison and the staff, together with adopted figures. Table IV-21 shows the respective estimates and adopted amounts by FERC accounts.

Conservation and load management programs are discussed in Section VI. The difference in estimates of cogeneration program expenses between Edison and staff is due only to the different escalation rates used.

TABLE IV-20

CUSTOMER SERVICE AND INFORMATIONAL EXPENSES
(Test Year 1983)

Item	System Estimates: Edison $M	Staff $M	Adopted $M
Conservation Programs			
Nonresidential	27,160	26,855	21,377
Residential	16,040	8,575	3,133
Solar	1,938	992	827
Public Awareness	1,836	914	800
Advertising	1,500	1,000	800
Measurement	3,439	3,318	2,655
Load Management Programs			
Nonresidential	11,920	9,666	4,806
Residential	12,174	9,362	5,943
Cogeneration Programs	3,779	3,684	3,642
Management/ Administration	1,982	1,699	1,566
Total	81,768	66,035	45,549

TABLE IV-21

CUSTOMER SERVICE AND INFORMATIONAL EXPENSES
(Test Year 1983)

Account		Edison $M	Staff $M	Adopted $M
907	Supervision	2,120	1,906	1,389
908	Customer Assistance	74,394	59,801	40,906
909	Infor. & Instr. Expense	5,254	4,329	3,254
910	Misc. Sales	-	-	
	Total	81,768	66,036	45,549

N. Administrative and General Expenses

Edison's estimate of administrative and general (A&G) expenses exceeds the staff's by approximately $22.7 million.

Table IV-22 breaks down this difference into amounts related to each issue. Table IV-23 presents a comparison of estimates of A&G expenses by accounts. The adopted level of RD&D expenditure is discussed in Section V.

TABLE IV-22

ADMINISTRATIVE AND GENERAL EXPENSE*

(Test Year 1983)

Item	System Estimates		
	Edison $M	Staff $M	Adopted $M
EEOC Litigation	140	-	-
Executive Comp.	2,163	2,172	2,172
Public Awareness**	3,578	2,132	2,132
Insurance SONGS 1	1,301	-	1,301
EEI Dues	567	-	-
Dues/Don.-Other	366	149	149
TMI Cleanup	525	-	-
Mgmt. Audit	500	-	-
Office Alterations	639	397	639
Abandoned Projects	2,065	500	500
Cap. A&G Expenses	(21,703)	(18,966)	(18,966)
Employee Benefits			
Stock Purch.	4,099	3,656	3,958
Dependent Medical	9,914	10,194	9,843
Sick Leave	3,860	3,578	3,455
Negotiated Chgs.	5,211	4,831	4,665
Trustee Payments	35,554	33,325	32,178
COLA - Pensions	2,228	2,066	1,995
Pension Insurance	46	41	41
Cap. Pensions & Benefits	(25,057)	(24,088)	(24,029)
Trending**	93,874	82,779	82,779
Escalation**	26,522	20,968	19,524
RD&D	17,650	17,650	15,356
Uncontested**	48,160	48,160	48,160
Total	212,202	189,544	185,852

(Red Figure)

*Excludes Franchise Requirements.

**Expenses for Public Awareness are shown in 1983 dollars and include trended and uncontested amounts. Thus, Trending, Escalation and Uncontested items do not include amounts for Public Awareness.

55701

TABLE IV-23

ADMINISTRATIVE AND GENERAL EXPENSES
(Test Year 1983)

Account	Item	Edison $M	Staff $M	Adopted $M
	Operation			
920	A&G Salaries	83,121	72,006	71,803
921	Office Supplies & Expenses	20,867	17,795	17,517
922	A&G Transferred - Credit	(25,268)	(21,822)	(21,705)
923	Outdoor Services Employed	3,398	2,722	2,683
924	Property Insurance	7,795	6,461	7,748
925	Injuries & Damages	11,639	11,573	11,546
926	Pensions & Benefits	70,129	64,922	62,538
927	Franchise Requirements*	12,522	12,472	12,472
928	Reg. Com. Expenses	2,012	1,970	1,952
929	Duplicate Charges - Credit	-	-	
930.1	Misc. Advertising Expense	320	312	308
930.2	Misc. Gen. Expense	29,741	25,510	23,177
931	Rents	1,096	1,073	1,062
	Total Operation	217,372	194,994	191,101
	Maintenance			
932	Maintenance of General Plant	7,353	7,023	7,223
	Total Maintenance	7,353	7,023	7,223
	Total A&G Expense	224,725	202,017	198,324

*At present rates.

1. EEOC Litigation Expense

The staff has excluded expenses for the cost of ongoing equal employment opportunity (EEOC) litigation because the final disposition of these cases has not been determined. Consistent with the policy we established in D.92549 in Edison's test year 1981

general rate case, we will adopt the staff position and exclude this expense pending final outcome of litigation. We are not finding that either the nature or the level of Edison's estimate of EEOC litigation expense is unreasonable; our determination runs only to the timing of any recovery of this expense.

2. Public Awareness Expense

Edison has requested $3.578 million during 1983 for non-conservation-related public awareness expenses, which include activities such as dissemination of information about electrical safety, specific Edison energy resources, and financial information; news releases; notification to customers of local system modifications; and a variety of educational services.

The staff has evaluated Edison's planned programs, and concludes that they generally adhere to Commission guidelines for public awareness activities. However, staff recommends that overall public awareness activity be kept at 1980 levels, and reduces Edison's request by $1.446 million. We will adopt the staff-recommended reduction, which is consistent with D.93887 in PG&E's test year 1982 general rate case.

3. Nuclear Replacement Energy Insurance Expense

In accordance with its understanding of D.92496 in OII 56, Edison has requested recovery of nuclear replacement energy insurance expense through base rates. Two staff witnesses made separate recommendations. The staff engineer, who had not made an analysis of the costs, recommended that this insurance expense should be recovered through the ECAC procedure. The staff accountant, however, supported Edison's request for recovery of the expense through base rates.

Edison and the staff accountant have correctly interpreted the policy we enunciated in D.92496 as it applies to this issue. The insurance premium for nuclear replacement energy is the type of cost

that should be excluded from ECAC and should normally be included in base rates. The insurance premiums are a type of fixed charge and are not a cost directly attributable to an energy source. As we have done in prior rate cases, we will allow the premium for this type of insurance to be recovered through base rates.

4. EEI Dues

Citing two prior general rate case decisions, D.93887 for PG&E and D.92892 for SDG&E, the staff has excluded Edison Electric Institute (EEI) dues on the basis that this expense does not produce a benefit to the ratepayers. Edison's position is that ratepayers receive substantial benefits as a result the dues Edison pays to EEI.

We have reviewed the facts developed on this record which Edison feels describe the benefits to ratepayers of the dues paid to EEI. We conclude that Edison did not present evidence sufficient to cause us to reverse our stated policy on this issue. We will, therefore, adopt the staff exclusion of EEI dues from the revenue requirement.

5. Other Dues and Donations

Edison has requested $366,000 for dues and donations to organizations other than EEI. These organizations include professional associations, local civic associations, and special interest groups.

Staff would disallow $217,000 of Edison's requested expense on the basis that this amount represents contributions to organizations which do not produce benefits to ratepayers. The staff made this reduction consistent with the policy we have adhered to in general rate decisions including the most recent PG&E and SDG&E decisions.

Edison took exception to staff's disallowances but failed to provide any support for ratepayer funding of the special interest-oriented organizations disallowed by staff.

We have reviewed the disallowances made by staff and find them to be reasonable. Our policy has been to disallow ratepayer contributions to organizations which provide no specific benefits to ratepayers. The burden is on Edison to show that the contributions for which it seeks ratepayer support provide such benefits. In this case, Edison has failed to meet its burden of proof.

6. Three Mile Island Cleanup

The staff recommends excluding from expenses Edison's share of the cost of cleanup of the Three Mile Island (TMI) facility. The staff believes that Edison's ratepayers would not receive any benefit from this expense. Edison, on the other hand, asserts that cleanup of TMI will have significant benefits to the electric utility industry, particularly to Edison since it has significant nuclear generating capacity.

The staff cited D.93887 in PG&E's test year 1982 general rate case as support for its position that this expense be disallowed. In that case we determined that PG&E's contribution to an EEI project designed to distribute information relating to the TMI incident should be disallowed. Edison contends that we are presented with a different situation in this case. We are of the opinion, however, that the basic issue is the same; accordingly, we will adopt the staff's recommended disallowance of TMI cleanup expense.

7. Management Audit

The staff has disallowed all expense associated with a management audit because no such audit will take place. We agree with the staff position. We are not at this time directing that a management audit be made in 1983 or 1984. We do not agree with Edison's position that either the expense should be allowed or this decision should categorically state that we will not order a management audit of Edison to be scheduled during 1983 and 1984. We will consider the method of recovery of audit costs if and when such an audit occurs.

8. Office Alterations

The staff has reduced expenses for the maintenance of general plant to provide for a lower level of office alterations expense. The staff believes that by better planning, Edison could avoid tearing down and reconstructing walls and moving people. Edison responds that its estimates are consistent with its space-management policy of avoiding the overbuilding of facilities, which would needlessly tie up significant capital well before need. If we were to follow the policy implied in the staff position, the result could be the construction of overbuilt, inefficient facilities resulting from forcing Edison into following an unsound space-management policy. We will adopt Edison's estimate for office alterations expense.

9. Abandoned Projects

Edison proposes to establish a methodology for the recovery of abandoned project costs on an estimated basis. This methodology would provide a 1983 test-year allowance of $2,065,000 and a 1984 allowance of $2,790,000. The methodology calculates an "Average Abandonment Ratio" (AAR) based upon historical major abandonments between 1977 and 1980. Edison would set up a balancing account which would collect the difference between estimated and recorded abandonment expense.

Staff opposes Edison's proposal on four grounds. First, the methodology would include recovery of costs for the Vidal project which was specifically rejected by the Commission in D.86794. Second, Edison made a similar proposal in its last general rate case which the Commission declined to adopt in D.92549. Third, the company would collect funds for abandonments that may never occur. Edison would retain these funds interest-free at ratepayers' expense until returned to ratepayers in the next general rate case. Lastly, there would be no opportunity to review the prudency of abandonment costs before rate recovery was granted.

The staff recommends that all actual abandonment costs for large projects be recorded as a deferred debit and be carried forward to the next general rate case, at which time their reasonableness will be reviewed and recommendations as to rate recovery will be made.

We concur with staff that the proposed methodology is ill-advised. In Edison's last general rate case, Edison made a similar proposal which we considered carefully and rejected in D.92549. In doing so we stated that "it was not our intention to cause reasonably and prudently incurred expenses to be borne by the stockholder merely because they slip down the crack between general rate cases. Rather, our position is simply that the forecasted amortization level methodology proposed by Edison is not acceptable for ratemaking purposes." (D.92549 mimeo, at p. 44.)

No new evidence has been submitted in this proceeding to change our minds. We will not adopt Edison's proposal.

For small projects, staff would allow Edison to recover estimated expenses for abandoned projects based on an historical average. Staff deems $500,000 as a reasonable estimate of small abandoned project expenses during the test year. We will authorize this amount.

10. Capitalized A&G Expenses

Edison and the staff used the same method to estimate capitalized A&G expenses. Their estimates differ only because the staff has estimated a lower level of A&G expenses, mainly resulting from trending differences. We will allow capitalized A&G expenses consistent with the level of A&G expenses which we adopt.

11. Employee Benefits

a. Stock Purchase Plan

Edison's estimate of expense for the stock purchase plan is a forecast based on the growth rate experienced by the plan. The staff reduced Edison's estimate based on a three-variable autoregressive statistical forecast of expenses for the plan. Edison

contends that the staff's model underestimates expense by failing to properly account for changes in the level of expenses which took place in 1979 and 1981.

Our review of this issue causes us to conclude that the staff's methodology significantly underestimates the expense of the stock purchase plan. We believe that, in this instance, Edison's forecasting technique produces a reasonable result; therefore, we will adopt Edison's estimate.

b. Dependent Medical Plan

Edison's estimate is based on a rate of increase of 18.5%. The staff recommends a 15% rate. In our opinion the 15% rate is more realistic; therefore, we will adopt staff's estimate.

c. Sick Leave, Negotiated Changes, and Trustee Payments

Edison's estimates of sick leave expense, negotiated changes, and trustee payment expense exceed the staff's estimates only because Edison's showing included higher payroll expense, which is the base upon which these three items are computed. The adopted expenses for the three items reflect the level of payroll expense we are including in the test year revenue requirement.

d. Pension Insurance and Fees

The staff used a lower rate of escalation for this insurance expense than was used by Edison. The adopted level of this expense reflects the staff's lower escalation rate.

e. Capitalized Pension and Benefits

The staff used the same methodology as Edison to estimate capitalized pension and benefits. The difference arises only from the lower level of pension and benefits estimated by the staff. The adopted capitalized pension and benefits reflect the level of such expense included in the adopted revenue requirement for the test year.

12. Trending

Edison used a trending method to develop its estimate of many A&G expenses. The staff did not; instead, it recommends that a budgetary approach be adopted. As part of its budget-oriented estimating method, the staff did not provide for additional A&G growth in the trended portions of Accounts 920, A&G Salaries; 921, Office Supplies; 930.2, Miscellaneous General Expenses; and 932, Maintenance of General Plant. The staff noted that the ratio of capitalized A&G expenses in Account 922 to total expenses in Accounts 920 and 921 has significantly declined. This shift is evident in Edison's proposed reduction in the percentage of Accounts 920 and 921 allocated to Account 922. As a result, many A&G personnel who would have been working on capitalized projects will be available for operations activities.

We agree that a budgetary approach is more appropriate for these accounts. Since changes in construction activities clearly affect A&G expenses, Edison should have quantified their impact on 1983 expenditures rather than simply extrapolating past expenditures.

Since we have recognized the shift to operational activities and the additional operational funds it provides in our adopted reduction in capitalized expenses, we will not provide for more growth in these A&G expenses.

O. Depreciation Expense

Edison's estimate of depreciation expense exceeds the staff's estimate by approximately $13.0 million. The difference between Edison and the staff relates principally to two issues: negative net salvage and SONGS Unit 1 sleeving.

1. Negative Net Salvage

The staff agreed to Edison's proposed depreciation rates and expense except for the calculation of the net future salvage ratio in six accounts. In the staff's judgment, the correlation

coefficient in the six accounts was too low for projections based on the regression analysis to be acceptable. The staff based its estimates on use of historical averages. We agree that the correlation coefficient is too low, and we adopt the staff estimates which result in a reduction of $8.3 million from Edison's requested 1983 depreciation expense.

2. SONGS Unit 1 Sleeving

The staff reduced Edison's depreciation expense estimate in concert with its recommendation to treat the SONGS Unit 1 sleeving cost as an extraordinary maintenance cost to be expensed rather than as a capital cost to be rate based. In Section IV-8 we adopt the staff recommendation; therefore, no depreciation expense is allowed.

P. Tax Expenses

1. Income Taxes

a. Economic Recovery Tax Act

Edison filed its application based on the provisions of the Economic Recovery Tax Act (ERTA) of 1981. Staff also based its estimates for 1983 and 1984 on ERTA requirements. In D.93887 we noted that ERTA makes the following changes in the tax laws affecting public utilities:

1. Provides for more rapid tax depreciation of plant and equipment added in 1981 and subsequent years under the adopted Accelerated Cost Recovery System (ACRS).
2. Eliminates the repair allowance deduction.
3. Makes minor changes in the ITC law.
4. Provides for a research and experimentation (R&E) tax credit.
5. Requires normalization of the tax benefits of ACRS as well as ITC; otherwise the utility is limited to straight line depreciation and loses the ITC.

6. Under the transition rule the normalization requirements are triggered by the first rate order issued after the passage of the ERTA.

D.93848 in OII 24 addresses the general policy issues relating to the appropriate ratemaking treatment to be adopted as a consequence of ERTA; therefore, we will not repeat such discussion in this order.

As a consequence of ERTA, rates adopted herein include increased rates of $103.6 million for 1983 and $110.7 million for 1984. Attached as Appendix D is a bill insert which we expect Edison to send to its customers informing them of the effect of ERTA on rates.

b. Normalized Income Taxes Under ACRS

Edison maintained during the course of the evidentiary hearings that if a net salvage method is used to determine depreciation rates then the cost of removal cannot be taken as a current tax deduction in the determination of federal income tax expense for the 1983 test year. The staff agrees with Edison's position.

We have adopted the net salvage method as the appropriate method to use in determining depreciation rates for the 1983 test year and have excluded cost of removal from federal income tax deductions for the 1983 test year in conformance with the normalization requirements of ERTA.

c. Normalized Income Taxes under IRS News Release IR-82-25

There is no support for Edison's position regarding normalization during the transition period as being precluded by ERTA from benefiting future ratepayers. ERTA contains no prohibition and does not address this issue. News Release IR-82-25 specifically requires that the normalization of the difference between ADR and ACRS for 1982 be recorded on Edison's books of account in a deferred

tax reserve. The balance in this account is the logical beginning balance to use in computing the average deferred taxes from depreciation to deduct from rate base for the 1983 test year. We will, therefore, adopt the staff's position regarding this issue, which does not impact income taxes for the test year. It does, however, affect rate base as developed in Section VIII of this opinion.

d. Tax Treatment for
<u>Spent Nuclear Fuel</u>

The staff's treatment of taxes on recovered nuclear fuel disposal expenses results in a staff estimate of 1983 tax expenses which is $4.7 million lower than Edison's figure, as discussed in Section IV.I. In addition it results in a $1,978,000 lower rate base. We adopt the staff's approach.

e. Normalization Tax Benefits
<u>Associated With SONGS Unit 2</u>

Although SONGS Unit 2 has not yet been included in cost of service for ratemaking purposes, it has met IRS requirements for plant in service in 1982. Edison will accordingly take ACRS depreciation and ITC associated with the plant in 1982. In order to comply with the requirements of ERTA, both the staff and the company have recommended that rates be set in this proceeding on a normalized basis. We have adopted this recommendation to assure eligibility for ACRS and ITS is preserved. Since SONGS Unit 2 is not yet included in rate base, however, the rates set in this proceeding do not recognize the costs or tax benefits associated with SONGS Unit 2. When the plant satisfies our requirements for inclusion in utility rate base, the ACRS and ITC associated with the plant will be normalized as required by ERTA. Pending such action, Edison will be ordered to normalize these benefits for 1982 in a deferred tax reserve. Our decision to treat the tax benefits associated with SONGS Unit 2 in this manner is based upon the unique facts presented and should not be construed as precedent with respect to any other pending questions regarding ERTA.

f. Recovery of ITC
SONGS Units 2 and 3

During oral argument Edison for the first time requested recovery of a percentage of investment tax credit (ITC) realized through the sale of a portion of SONGS Units 2 and 3 to the City of Anaheim.

We think that this issue more appropriately should be resolved in the separate proceeding regarding the ratemaking treatment of SONGS Units 2 and 3. In that proceeding our staff and other interested parties will have the opportunity to address this issue in the context of other cost issues associated with these facilities.

2. Ad Valorem Taxes and Other Taxes

Edison's estimate of ad valorem taxes is greater than the staff's estimate because of the higher plant additions assumed by the utility, as well as Edison's treatment of the SONGS Unit 1 sleeving cost as a capital addition rather than as an extraordinary expense as recommended by the staff.

Edison's estimate of other tax expense is greater than the staff's estimate because of the lower level of wages assumed by the staff.

Our adopted ad valorem taxes and other taxes reflect the adopted plant amount and the adopted wage levels, respectively.

3. Tax Equity and Fiscal Responsibility Act of 1982

On September 3, 1982, President Reagan signed into law the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA).

TEFRA contains the following provisions which affect public utilities:

a. The tax basis of plant additions eligible for ACRS must be reduced by 50% of the 10% ITC generated by such plant additions for 1983 and subsequent years.

b. Estimated tax payments required to avoid underpayment penalties must equal 90% of the current year's tax liability with the remaining tax due 2½ months after the close of the tax year beginning in 1983.

c. The Federal Unemployment Tax (FUTA) wage base will be increased from $6,000 to $7,000 and the tax rate will be increased from 3.4 to 3.5% in 1983. The net effective federal tax rate, therefore, will increase from 0.7 to 0.8%. The state credit of 2.7% will not change. Effective January 1, 1985 the federal tax rate will be increased to 6.2% and the state credit will be increased to 5.4%.

d. Construction period interest and expenses must be capitalized and amortized over ten years for real property other than residential real property. This provision has no impact on rates.

e. Limitations will be imposed on utility pension plan contributions deductible for tax purposes.

We have incorporated the requirements of TEFRA in our adopted revenue requirement. The effect of TEFRA is to increase rates by $7.9 million for 1983, and $8.5 million for 1984.

V. Research, Development and Demonstration Program

Edison has requested $39.9 million in 1983 and $47.1 million in 1984 for funding of its research, development and demonstration (RD&D) programs. Edison has identified 29 program areas which are described in Exhibit 6. In addition Edison contributes to the Electric Power Research Institute (EPRI) and West Associates (WEST). Edison has requested $13.6 million in 1983 and $15.8 million in 1984 for research support to EPRI and other organizations. Edison's request is represented in Table V-1.

Staff supports Edison's funding request with one exception. Staff does not support recovery of AFUDC for the abandoned fuel cell program. Staff therefore adjusts Edison's request to $34.6 million in 1983 and $41.8 million 1984. The treatment of the fuel cell program is discussed separately above.

Edison has requested that funding for basic research be brought up to pre-1980 funding levels. In the last few years Edison has reduced basic research and diverted money to the demonstration phase of new technologies because the total revenues produced by the demonstration projects have been less than the operating costs.

Edison has grouped the various programs under seven categories: (1) resource conservation ($1.4 million); (2) renewable energy resources ($8.7 million); (3) advanced energy technologies ($10.1 million); (4) energy management ($1.5 million); (5) environmental assessment ($5.5 million); (6) emissions reductions ($2 million); and (7) energy transport ($600,000). These programs are listed in the order of priority given the programs by staff.

TABLE V-1

SOUTHERN CALIFORNIA EDISON COMPANY

R&D ESTIMATED PROGRAM EXPENSES
($000s)

Line No.	Item	Recorded 1980	Estimated 1981	1982	1983	1984
1.	ADVANCED COAL TECHNOLOGY	-	92	150	300	600
2.	ATMOSPHERIC PROPERTIES	1,787	1,100	750	1,000	1,400
3.	COAL FOR OIL	-	1,031	500	750	1,400
4.	COASTAL NATURAL RESOURCES	1,448	700	500	1,000	1,200
5.	CONSERVATION OF ENERGY IN BLDGS.	305	393	300	500	600
6.	CRITICAL WILDLIFE	-	300	-	-	-
7.	DIRECT COMBUSTION OF COAL	11	484	120	500	500
8.	ECOLOGICAL CRITERIA	474	250	250	500	500
9.	ELECTRIC POWER TRANSMISSION	640	384	450	600	700
10.	ELECTRIC VEHICLES	109	76	100	200	350
11.	ENERGY RECOVERY FROM WASTE	378	207	270	400	700
12.	ENVIRONMENTAL ASSESSMENT OF R/A	-	-	500	500	500
13.	FUEL CELLS	186	197	175	7,907	8,208
14.	HAZARDOUS/RECOVERABLE WASTE	10	400	500	1,000	1,000
15.	MHD	530	57	75	300	500
16.	NOx CONTROL	539	580	300	1,000	1,250
17.	PHOTOVOLTAIC POWER GENERATION	-	-	-	400	600
19.	REGULATORY SUPPORT AND SITING	1,130	694	575	1,000	1,200
20.	SCAB	752	573	500	500	500
21.	SMALL HYDRO	2	116	60	300	500
22.	SOLAR POWER GENERATION	454	740	600	700	1,000
23.	STACK EMISSIONS	120	170	175	500	700
24.	SYNTHETIC FUELS	2,445	374	240	750	1,100
25.	SYSTEMS SUPPORT	64	398	500	850	800
26.	THERMAL RESOURCE UTILIZATION	166	188	350	500	700
27.	WATER CONSERVATION	208	70	300	500	750
28.	WIND	141	300	225	500	750
29.	WIND & SOLAR RESOURCE ASSESSMENT	150	135	185	300	500
30.	GEOTHERMAL	331	4,550	4,330	6,500	6,700
31.	RESEARCH SUPPORT (EPRI, WEST, etc.)	8,600	10,030	11,700	13,600	15,800
32.	MANAGEMENT/ADMINISTRATIVE	837	990	1,000	1,300	1,600
33.	LOAD RESEARCH	457	452	-	-	-
34.	SUBTOTAL EXPENSE	22,324	26,031	25,680	44,657	53,008
35.	LESS: COST SHARING	-	(1,730)	-	-	-
36.	REVENUES FROM DEMOS.	-	(2,924)	(3,000)	(4,000)	(4,500)
37.	NON-R&D ADMIN.	(362)	(377)	(680)	(750)	(1,000)
38.	GRAND TOTAL	21,962	21,000	22,000	39,907	47,108

In reviewing the specific program descriptions within each category, we observe that certain programs contain objectives which appear to be duplicative of others. For instance, the South Coast Air Basin (SCAB) and Atmospheric Properties programs, totaling $1.5 million, both have the objective of studying and mitigating the effect of air pollutants within the South Coast Air Basin. The SCAB program is also funded in large part by EPRI, which undoubtedly performs similar studies for Edison.

Likewise, the descriptions of the Stack Emissions and Direct Combustion of Coal programs, totaling $1 million, are very similar to the SCAB program. Also, the Ecological Effects Criteria for Secondary Standards program is expressly integrated into the Atmospheric Properties and other programs. We note a certain degree of overlap among the management/administrative support programs as well.

Neither Edison nor our staff presented evidence to distinguish the various programs from one another. We therefore are at a loss to determine whether some programs could be subsumed under others, or whether certain programs are worthwhile to pursue individually. We note, however, that it is Edison's burden to demonstrate the reasonableness of its estimated test year operating expenses. We will expect Edison in its next general rate case to distinguish carefully the need for RD&D programs which have overlapping objectives or which are being partially funded by organizations like EPRI.

We next observe that a number of programs, particularly under the category of environmental assessment, include among their objectives "minimiz[ing] retrofit requirements of environmental regulations" (Atmospheric Properties program) or "identifying and modifying environmentally over-restrictive laws and water/land use policies which will restrict alternate/renewable energy development" (Environmental Assessment and Management for Renewable and Alternate Resources program). Similar language appears in the SCAB program, the Coastal Siting and Resource Management program, the Ecological

Effects Criteria for Secondary Standards program, and the Hazardous and Recoverable Waste program.

We question whether programs with the objective of avoiding or mitigating environmental regulation are properly funded by ratepayers. It appears to us that where local, state or federal governmental agencies have established environmental regulations, Edison is bound to comply with them. More fundamentally, we question whether this type of program objective can seriously be considered RD&D. We will disallow one-third of the proposed funding for these programs, amounting to $1.5 million. We instruct Edison to redirect remaining funding for the above-mentioned programs away from objectives which could reasonably be characterized as avoidance of environmental regulation. We will carefully scrutinize Edison's expenditures in its next general rate case to ensure that no RD&D funding is devoted to such objectives. It is not our intent, however, to discourage genuine research to develop needed information on environmental impacts of utility actions or more efficient means of achieving environmental goals.

Another area of concern is that Edison seeks funding for many programs which appear to provide no unique benefits to Edison's service territory. These programs include the NO_x Combustion Control program, the Electric Power Transmission System program, the Conservation in Energy Buildings program, and the Synthetic Fuels program. Total requested funding for these programs is $3.05 million. In addition Edison requests funding totaling about $1.55 million for programs oriented towards the use of coal. These are the Coal for Oil program, the Advanced Coal Technology program, and the Direct Combustion of Coal program. Although we are supportive of coal projects which will provide specific benefits to California, we are not convinced by Edison's showing that the programs for which funding is requested will confer such benefits. Staff assigns lowest priority to the Coal for Oil, Electric Vehicles and Synthetic Fuels programs.

With respect to each of these program areas, we are aware that private industry and research organizations are conducting major research, development and demonstration programs. The reason is that these programs provide potential benefits to a wide spectrum of industries, including the electric utility industry. We are concerned that Edison's funding of its proposed programs may be duplicative of other efforts, and that Edison could obtain more cheaply the benefits of these programs through private research organizations. In our view RD&D programs funded by Edison's ratepayers should be designed to confer benefits of special value to Edison's service territory. Programs which exploit Edison's wind, solar and geothermal resources are more worthwhile to Edison than a program which, for example, experiments with electric vehicles.

We find it preferable for entities other than Edison to finance programs which are more broadly geared to industry in general. We therefore will reduce the total budget of the programs described above by one-half, from $4.6 million to $2.3 million for 1983. Edison may allocate the authorized expenses among these programs as it deems prudent. In addition, we will disallow entirely the $200,000 proposed expenditure on the Electric Vehicles program. It is our policy to discourage utility expenditures on RD&D projects which promote increased demand for utility service.

A large portion of 1983 expenses is requested under the Geothermal program ($6.5 million). We encourage Edison to continue its development of geothermal resources within its service area. We, of course, expect that the funding authorized will be applied only to projects other than the Edison Heber dual flash facility for which we recently granted a certificate of public convenience and necessity. (D.82-10-049.)

In determining a reasonable level of funding for RD&D, we are immediately struck by the dramatic increases in expense levels over 1980-1982 which Edison has requested. Although Edison indicated that a large portion of the increase is due to its desire to fund research at pre-1980 levels, no more than $15.6 million of the 1983

request is for so-called "core" research. The balance of $24.3 million is for demonstration projects and contributions to EPRI. The balance alone exceeds total authorized funding levels between 1980 and 1982.

In examining the requested budget levels for individual programs, we observe expense increases ranging from 25 to 300% between 1982 and 1983/1984 levels. Examples include the NO_x Control program which increases from $300,000 in 1982 to $1 million and $1.25 million in 1983 and 1984, respectively; and the Coal for Oil program which increases from $270,000 in 1982 to $400,000 in 1983 and to $700,000 in 1984. The management/administrative support program shows corresponding increases.

We commend Edison for embarking on an ambitious RD&D program. Many of the programs are meritorious and will undoubtedly benefit the ratepayers. Nevertheless, while we understand Edison's need for increased funding for research programs, we find no justification in the record for such sharp increases over the next two years. We are particularly concerned that substantial funding increases come at a time when economic conditions are poor and when many ratepayers are already hard-pressed by ever-increasing utility bills. We therefore find that a reduction in Edison's RD&D budget request is in order.

Edison's 1983 budget request, exclusive of outside research support funding and the proposed amortization of the fuel cell program, is $18.6 million. This compares to Edison's 1982 budget level of $10.3 million. We have already reduced the funding of certain program areas by $4 million. We will reduce the remaining budget by 20%, or to $11.7 million. This amount still represents a 14% increase over 1982 levels. We will authorize Edison to provide funding to EPRI at the level established by EPRI's actual billing to Edison for 1982, which is $12,220,000. This is consistent with the treatment of EPRI expenses allowed for PG&E in its last general rate decision. Funding for WEST Associates is authorized at

requested levels and included in other dues and donations, discussed in Section IV.N.

For 1984, we will apply the escalation rates adopted in the attrition process to RD&D funding.

In Edison's next general rate case, we intend to scrutinize Edison's RD&D programs still more carefully. We expect Edison to consolidate programs with similar objectives, to reduce funding for programs which outside organizations also fund, and to justify specific expense levels of each program. We also expect Edison to devote the majority of its RD&D activity to the development of resources particular to Edison's service area, which we believe confers the greatest benefits to Edison's ratepayers.

Edison proposes that the Commission adopt certain guidelines for the recovery of RD&D costs. These guidelines, which were not challenged by the staff or any other party, are as follows:

1. <u>Research and Development Expenses</u>

   Research and development programs should be planned on a programatic basis and the level of funding based on a percentage of Edison's revenue.

2. <u>Demonstration Costs</u>

   Demonstration costs should be separately identified and expenditures forecast on a project-by-project basis, with the following accounting guidelines to be followed for recovery through rates.

   a. <u>Capital Costs</u>

      Capital costs for demonstration facilities are to be recovered through base rates through FERC Account 103, Experimental Electric Plant Unclassified, in accordance with FERC and Commission accounting rules.

   b. <u>Fuel Expenses</u>

      The fuel cost of a demonstration project is to be recovered through ECAC up to an amount equal to the average cost of oil.

Any amount in excess of the average oil cost is to be recovered through base rates as part of the O&M estimate in a general rate case.

c. O&M Expenses

The O&M expenses of a demonstration project are to be recovered through base rate and accounted for in a separate account, Experimental O&M Expenses. Such expenses will be forecasted by Edison every two years and included in general rate case estimates.

On December 1, 1982, we issued D.82-12-005 which established uniform guidelines with respect to major energy utility requests for ratepayer-funded RD&D projects in general rate proceedings. As one of the adopted guidelines we provide that the recovery of RD&D expenditures shall be expensed in the various accounts in conformance with the FERC Uniform System of Accounts. RD&D expenditures resulting in the construction of tangible plant shall be capitalized and recovered through depreciation and return on investment when the plant becomes used and useful. Exceptions to these cost recovery guidelines will be handled on an ad hoc basis.

We expect Edison to comply with these guidelines for the construction of RD&D projects. We will not adopt Edison's proposed guidelines which differ from those adopted in D.82-12-005 as we believe that flexibility in the ratemaking treatment of RD&D expenses is desirable.

VI. Energy Conservation and Load Management

We have made a firm policy commitment toward encouraging and promoting energy conservation, load management, cogeneration, and renewable energy resources, in the belief that these energy options can contribute significantly to a reduction in ratepayer costs. The basis for this belief is that these resources will decrease utility reliance on costly and potentially undependable sources of fuel, reduce the need for massive, long-lead-time investments in

conventional generating facilities, and conserve scarce, nonrenewable natural resources.

To this end, we have authorized funding for many energy conservation and load management programs. Interim orders providing funding, surcharges, carryovers for unspent funds, and wide management discretion with respect to the use of the funds provided have demonstrated our recognition of the need for these programs. To ensure that the programs contribute to the ultimate goal of least-cost energy supply, we have concomitantly sought to develop means whereby the costs and benefits of these programs may be measured accurately so that only those programs which provide net benefits receive ratepayer support.

Conservation and load management program expenditures are recorded in Edison's Customer Service and Informational Expenses accounts (see Section IV.M). Table VI-1 presents a summary of the differences between Edison and staff recommendations for test year 1983 conservation programs receiving expense treatment; Table VI-2 contains comparable information for Edison's load management programs. Descriptions of the proposed programs and of staff's recommended adjustments are described in Section VI.C.

As these tables show, Edison now requests $77,990,000 for conservation and load management programs receiving expense treatment in 1983. In addition, Edison has stipulated to and now requests rate-base treatment of the capital costs of its Demand Subscription Service (DSS) and Residential Air-Conditioning Cycling (ACC) programs, which would result in a further 1983 revenue requirement of $1,568,000. Inclusion of these two programs at requested funding levels but with expense treatment of the capital costs would have increased Edison's 1983 revenue request by more than $15 million.

The requested load management programs would entail incentive payments in excess of $8,000,000 in 1983, in addition to the direct program costs. These incentive payments would be recovered through rate design, as discussed in Section VI.C.

Apart from the programs for which Edison requests base rate funding in this rate case, it should be remembered that Edison's Residential Conservation Financing Program and solar demonstration program will be financed through balancing accounts in 1983, and are examined in other proceedings.

Staff recommends that Edison's conservation and load management programs receiving expense treatment be funded at $62,352,000, approximately a 20% reduction from Edison's request.

TABLE VI-1
CONSERVATION PROGRAMS
Base Rate Expenses
Test Year 1983

Item	Edison $M	Staff $M	Adopted $M
Nonresidential Conservation			
Escalation	-	(305)	(351)
Uncontested	27,160	27,160	21,728
Residential Conservation			
Residential New Construction	7,013	-	-
Regulatory Support	617	345	493
Escalation	-	(180)	(98)
Uncontested	8,410	8,410	2,738
Solar			
Solar Marketing	327	182	146
Solar Retrofit	1,072	339	271
Regulatory Support	110	59	88
Escalation	-	(17)	(22)
Uncontested	429	429	344
Public Awareness			
Public Awareness	1,836	1,000	800
Escalation	-	(86)	-
Advertising			
General Advertising	1,500	1,000	800
Measurement			
Potential Savings	461	406	369
Goal Optimization	560	479	448
Residential Behavior	652	596	522
Econometrics	274	357	218
Persistence Studies	222	166	178
Attitude Study	485	439	388
Data Purchases	107	84	86
Contingency Fund	-	200	-
Escalation	-	(84)	(96)
Uncontested	678	678	542
Management/Admin.			
Uncontested	1,083	890	866
Escalation		(8)	(10)
Total	52,996	42,536	30,448

(Red Figure)

TABLE VI-2
LOAD MANAGEMENT PROGRAMS
Base Rate Expenses
Test Year 1983

Item	Edison $M	Staff $M	Adopted $M
Nonresidential Load Management			
C/I Load Control*	5,658	5,219	1,655
C/I Thermal Storage	2,632	1,316	260
New LM Equipment Evaluation	1,445	1,097	1,156
Regulatory Support	742	610	594
Uncontested	1,443	1,443	1,154
Escalation	-	(19)	(13)
Residential Load Management			
Swimming Pool Program	1,941	730	584
Residential New Equipment Evaluation	3,700	2,272	2,960
Load Management Information	1,660	1,577	1,328
Uncontested	4,251	4,251	609
Escalation	-	(27)	(36)
Regulatory Support	622	559	498
Management/Admin. Support			
Adjustment	899	795	719
Escalation		(7)	(9)
Total	24,993	19,816	11,459

(Red Figure)

*Includes Commercial/Industrial Air-Conditioning Cycling, Air Conditioning Chillers, Energy Cooperatives, Interruptive Rates, and Customer Computer Dispatch Programs.

A. Adopted Funding Levels and Policies

1. General

Conservation and load management provide valuable, desirable new energy supplies. In authorizing funding for conservation and load management programs, we are concerned that increases in program expenditures be authorized at a rate which permits orderly implementation of the most cost-effective programs possible.

Funding for Edison's conservation and load management programs has increased rapidly. In D.86794 dated December 1976, we authorized Edison to expend $4.3 million for conservation programs in 1977. In the next general rate case, we authorized $20 million for 1979 conservation and load management programs. And, most recently, we allowed $39 million in D.92549 for the 1981 budget. In D.92549 we also placed several conservation-related requirements on Edison and stated that a penalty would be imposed if those requirements were not met. Edison has complied satisfactorily with D.92549. Therefore, we conclude today that no penalty is in order.

In establishing Edison's conservation and load management budget, we will follow a procedure similar to that used in D.93887 in PG&E's last rate case. We will make explicit modifications to certain programs, comment on many of the programs proposed by Edison, and establish certain policy guidelines.

Within the boundaries of the guidelines and budget established in this decision, Edison's management will have discretion to establish priorities and allocate funds to maintain a well-rounded program and to maximize energy savings.

The staff has developed a set of guidelines for the establishment of funding priorities for conservation programs. The staff guidelines, as given in Exhibit 135, are as follows:

> "<u>Priority 1</u>
> "The following guidelines apply to Priority 1 programs:
> "1. The energy savings are directly attributable to the program.
>
> "2. The magnitude of the energy savings is relatively large.
>
> "<u>Priority 2</u>
> "The following guidelines apply to Priority 2 programs:
> "1. Energy savings are directly attributable to the program.
>
> "2. The magnitude of the energy savings is relatively small.

"Priority 3

"The following guidelines apply to Priority 3 programs:

"1. Energy savings are not directly attributable to the program."

Activities related to basic program design and measurement and regulatory support activities, except solar, are rated by the staff as Priority 1. The staff witness stated that the priorities he set reflect merely a relative value and that they do not constitute a recommendation for the reduction or elimination of any program.

Edison states that it is in basic agreement with the priorities established by the staff. Edison notes, however, several potential impacts which it believes could negate its attempts to develop conservation programs which: (a) meet the needs of certain target markets, (b) are responsive to regulations, and (c) address new techniques and applications.

Edison points out that the staff has placed programs which do not achieve direct energy savings in Priority 3. Priority 3 thereby includes the community energy conservation development (CECD) program which is designed to assist difficult-to-penetrate and often neglected markets such as the economically disadvantaged or non-English speaking customer. The CECD program is responsive to criteria established by this Commission, as well as other state regulatory agencies and federal agencies. Edison feels that reducing or eliminating its CECD program would severely constrain efforts to reach those special segments within the residential community. Similarly, Edison points out that the staff has placed Edison's Study/Evaluate Residential Conservation Technologies program in Priority 3. Edison believes that a reduction or elimination of funding for this program would hinder its ability to analyze new conservation technologies, thereby handicapping its efforts to maintain aggressive, forward-looking, and cost-effective conservation programs. The staff agrees that such a negative impact could result with respect to Edison's conservation mandate.

Edison's concerns are well taken. We shall not specifically adopt staff's proposed priorities. However, we note their general consistency with our policy established in D.93887 to emphasize programs with directly attributable energy savings and to de-emphasize general advertising and public awareness efforts.

2. Reallocation and Carryover of Funds

As we did for PG&E in D.93887, we give management limited discretion to reallocate base rate funds among individual programs in amounts up to $2,500,000. We do not grant Edison's request to permit reallocation at Edison's discretion among all programs. Reallocation of any amount of funds to or from the three major categories of Residential Conservation, Nonresidential Conservation, and Load Management, or budget adjustments in excess of $2,500,000 for any program shall be made the subject of an advice letter filing.

Funds allocated under this budget shall only be spent on conservation and load management programs. Any funds not spent during a year shall be carried forward consistent with the procedure we establish today.

Staff and Edison presented proposals for carrying over funds which remain unspent at the end of a year. The staff originally recommended in Exhibit 135 that unspent funds be used to reduce revenue requirements in the following year, for example that, "...the funding level adopted by the Commission for 1983 be reduced by one-half of the 1982 ending balance..." Edison, however, in the belief that the unspent 1982 year-end balance of conservation funds should be used to supplement 1983 programs, proposed in Exhibit 11-D a redirection process which could serve as a means of notification to the Commission of unspent funds. Edison's proposed allocation of these funds would become effective if not denied by the Commission within 30 days. The staff later agreed in Exhibit 146 that unspent funds should supplement the next year's budget allotment, and proposed a different procedure from that presented earlier.

We will adopt a procedure for carry-over of unexpended funds similar to staff's recommendations in Exhibit 146. If Edison, as of the end of 1982 or any subsequent year, has underspent base-rate funds authorized for conservation or load management programs, Edison shall seek Commission approval of its proposed allocation through an advice letter filing no later than March 1 if the amount is greater than $2,500,000 or if Edison proposes reallocation of funds to or from the three major categories. Otherwise, Edison may allocate the money to supplement conservation and load management expenditures in the following year as it sees fit.

We will require that Edison report no later than February 15 of each year on its conservation and load management expenditures during the prior year and its proposed budget for the current year. Any carryover amounts, and rate base, expense, and load management incentive components should be clearly shown.

Since load management incentive payments are recovered through rate design, we note that the ERAM adopted in this decision will prevent overcollection or undercollection of these incentive funds relative to the amounts which are actually disbursed; thus no carryover of unexpended payments will occur.

3. Funding Levels

In establishing Edison's 1983 budget for conservation and load management, we approve funding through several ratemaking mechanisms, as discussed in detail in Section VI.C. We approve Residential Conservation Service (RCS) funding of $5,000,000 which will be covered through a balancing account, load management incentive payments of $3,500,000 which will be recovered through rate design as transfer payments, and eventual recovery of Commercial/Industrial (C/I) and Residential Air-Conditioning Cycling equipment costs through rate base treatment.

We do not allow Edison's request for 1983 funding through expense treatment of the following amounts, for the reasons indicated:

Residential Conservation:	
Denial of Residential New Construction and removal of RCS from base rates	$12,000,000
Solar:	
Elimination of certain programs	877,200
Public Awareness reduction	835,500
Advertising reduction	500,000
Nonresidential Load Management:	
Rate-base treatment of C/I Air-Conditioning Cycling equipment	3,589,000
Treatment of C/I thermal storage incentives as a transfer payment	2,307,000
Residential Load Management:	
Delay in air-conditioning cycling installations	1,339,500
Deferral of DSS funding approval	2,302,100
Denial of swimming pool direct control	1,210,900
Total	$24,961,200

This leaves $53,028,800 of Edison's request for $77,990,000. We adjust this amount to reflect the lower escalation rates adopted in this decision. We approve $600,000 as our estimate of operation and maintenance funding which will allow installation of 10,000 residential air-conditioning cycling units in 1983. We then reduce the remaining funding request by 20%, across the board. As a result of these adjustments, we approve $41,907,000 in program expenses, with funding targets by conservation/load management category as shown in Table VI-3. Edison's management will have discretion to reallocate these funds within the limits discussed previously.

TABLE VI-3

ADOPTED CONSERVATION AND LOAD MANAGEMENT PROGRAMS

Base Rate Expenses

Test Year 1983

	System Estimate $M
Nonresidential Conservation	$21,377
Residential Conservation	3,133
Solar	827
Public Awareness	800
Advertising	800
Measurements	2,655
Nonresidential Load Management	4,806
Residential Load Management	5,943
Management/Administrative	1,566
Total	$41,907

Our reasons for this general cut are twofold. As we did in last year's PG&E rate case decision, we find that some belt-tightening in this time of economic hardship is in order. Further, we believe that a budget reduction of this size, coupled with the allowance of management discretion in allocating the reduction, will "trim the fat" and result in a more cost-effective effort.

We will allow Edison to recover $3,500,000 through rate design in 1983 for new load management program incentive payments, which is consistent with the cuts in direct program expenses we have made. Of this amount, $1,846,000 is allowed for C/I Thermal Storage incentives. Combining these incentives with the approved RCS balancing account funds, the eventual recovery of commercial air-conditioning cycling program costs through inclusion in the rate base, and the approved funding of program expenses, we approve $52,342,00 or 67% of Edison's request for program expenses of $77,990,000. We defer decision on the DSS program, for which Edison has requested revenue of $3,337,100 ($2,302,100 in expenses and

$1,035,000 due to rate-based equipment costs) and $4.5 million in incentive payments during 1983.

In the attrition year, we will allow escalation of funding for that portion of Edison's conservation and load management program which receives expense treatment, consistent with the attrition procedure adopted in this decision. We will increase the toal amount of load management equipment costs allowed in rate base in 1984 by an amount equal to that authorized in 1983. We will give Edison discretion to allocate this amount between the residential and nonresidential ACC programs, though we expect Edison to make roughly equivalent expenditures for the two programs depending on equipment availability.

B. Cost-Effectiveness Calculations

Edison estimates that its proposed 1983 conservation and load management programs (excluding cogeneration) would save 1.36 billion kWh and reduce peak demand by 616 MW. The desirability of these reductions must be measured against the program costs. Table VI-4 shows th life-cycle utility cost per kilowatt-hour saved due to conservation programs for which Edison has quantified the energy savings. In Table VI-5, Edison's calculations of ratios of program benefits to program costs are shown for the proposed load management programs. The benefits due to load management programs which Edison used in these calculations are based on Edison's "avoided capacity costs" filed in August 1981 for purchases from cogenerators and small power producers.

Staff has pointed out that there is great variation in the accuracy of the energy savings assumed for the different programs in Table VI-4. This directly affects the reliance which we can place on cost-effectiveness assessments of the individual programs. In order to determine the desirability of programs for which there is a low level of confidence in the level of energy savings which will be realized, we must weight more heavily other factors such as unquantifiable benefits.

TABLE VI-4
COST OF CONSERVATION SAVINGS*
Test Year 1983

Conservation Program	Cost** (¢/kWh Saved)
Non-Residential Conservation:	
C/I Audits	0.22-1.68
Pump Tests	1.21
Residential Conservation:	
Outdoor Lighting	0.25
Basic Audit Surveys	6.20
Mobile Home Audits	3.48
New Customer Booklet	7.89
Energy Efficient Appliances	3.19
Residential New Construction	12.97
Conservation Planning Centers	6.11
Conservation Corner	15.36
Wrap-up	1.37
Solar:	
Solar New Construction	2.44
Solar Retrofit	2.33

*Source: Table B3, Exhibit 135.
**Cost of utility program only.

TABLE VI - 5

BENEFIT/COST RATIOS OF LOAD MANAGEMENT PROGRAMS[1]

	1983, Expensed		1983, Capitalized		1985, Capitalized[2]	
	UP*	NP*	UP	NP	UP	NP
Commercial-Industrial:						
A/C Cycling	1.80	1.00	1.50	.89	1.94	1.16
A/C Chillers	1.07	1.07	.75	.75	1.04	1.04
Computer Dispatch	30.27	1.18	21.63	1.16	29.89	1.52
Thermal Storage	1.42	1.42	1.42	1.42	1.79	1.79
Agricultural TOU	1.68	1.68	1.53	1.53	3.89	3.89
Residential:						
A/C Cycling	1.90	1.01	1.54	.90	2.29	1.26
Swim. Pool Tripper	2.54	2.54	2.52	2.52	5.02	5.02
Swim. Pool Load Control	1.47	1.01	1.25	.90	1.64	1.18

[1]Source: Table VII-C and Table VII-E, Exhibit 26.

[2]Assumes (1) increased production levels of load control devices will result in additional economie (2) field procedures will be refined through experience to reduce customer contact costs; (3) ther will be economies of scale involving installation costs; (4) all the programs listed are voluntary and (5) incentives will generally remain at the present levels.

*UP = Utility Perspective and NP = Non-Participant Perspective

Staff used Edison's projections of the average cost of oil-generated electricity in 1983 (8.6¢/kWh) to compare to conservation programs in evaluating cost-effectiveness. Staff stated that comparison of program costs to the summertine, on-peak marginal cost of electricity including both energy and capacity components (13.55¢/kWh according to Exhibit 8) would conform to Commission policy, as established in D.91107:

> "Where the marginal cost of conserved energy is less than the marginal cost of new energy supply, the former should always be the investment ofchoice."

Neither method used by staff is consistent with the Commission policy set forth in D. 91107. The average cost of oil-generated electricity is clearly not the marginal cost of new energy supply. Further, use of the summertime, on-peak marginal cost of electricity would greatly overstate the value of most energy conserved. Consideration must be given to the time at which the energy is conserved; only savings during the summertime on-peak period should be compared to the summertime on-peak marginal cost.

The cost-effectiveness of various conservation and load management programs has been examined extensively in a number of proceedings during the last several years, including recent rate cases, OII 42, and the conservation financing and RCS proceedings. Four tests of cost-effectiveness have been formulated: the societal, participant, nonparticipant (or ratepayer), and utility tests.

The conservation programs proposed by Edison in this rate case have not received the level of scrutiny applied in other recent proceedings. The staff's comparison of the utility costs of these programs to the cost of oil-generated electricity appears to be as rough application of the utility test. However, none of the other three tests were used by Edison or by staff in evaluating the desirability of Edison's conservation programs.

The information which has been developed only allows us to evaluate the programs from the utility perspective and the nonparticipant perspective based on test-year marginal and average costs. The weighted test-year (short-run) marginal costs shown in Table XII-9, which we adopt for use in rate design, equal 8.55¢/kWh,

and system average costs (based on January 1, 1983 rates) are 7.65¢/kWh. This produces a test year marginal cost-average cost gap of 0.9¢/kWh. Almost none of Edison's proposed programs would meet the nonparticipant test based on this test-year data.

The short-run approach described above has limitations. It does not capture all the savings resulting from conservation programs. Until now, we have used the short-run marginal cost-average cost differential because it used data already filed in rate cases and was conservative. The short-run differential has on its own been large enough to justify a wide range of utility conservation programs. It has not been necessary to increase the complexity of our cost-effectiveness analyses by attempting to project future electricity costs as part of a longer-term marginal cost analysis. In this proceeding, staff has recommended that intermediate-run marginal costs be used in evaluating the cost-effectiveness of conservation programs. We agree that this approach would better measure program benefits, which occur over the life of the conservation programs being examined.[7]

The intermediate marginal cost of 8.94¢/kWh developed by staff in Exhibit 88 includes the value of postponed additions to generation, transmission, and distribution plant. The staff methodology is not sufficiently refined to permit its adoption here. However, we note that while we have not included avoided transmission and distribution costs in the adopted test year marginal costs, we agree that they should be included in a calculation of intermediate-run marginal costs avoided by conservation savings. In the OIR 2 compliance proceedings (A.82-03-26 et al.), we will determine

---

[7] A further refinement would be to calculate the marginal cost over the assumed life of the conservation measure.

appropriate methodologies for calculating utility costs avoided by purchases from cogenerators and small power producers.[8] By the next Edison rate case, a more refined method of calculating the value of conservation savings should also be possible.

All but two of the conservation programs for which savings have been quantified clearly meet the utility cost-effectiveness test, using either the test-year or intermediate-run marginal costs cited above. We instruct Edison to phase out Conservation Corner, which at 15.36¢/kWh saved is the most costly program shown in Table VI-4, as quickly as is feasible in 1983. We do not allow funding for the Residential New Construction program, which is shown to cost 12.97¢/kWh saved, primarily because of its high cost.

Evaluation from the nonparticipant's perspective is more problematic. In A.61066, staff calculated Edison's marginal cost-average cost gap to be 3¢/kWh in 1982. As noted above, the 1983 differential has been calculated to be less than 1¢/kWh. While this value does not capture the total value of savings due to conservation programs, it is clear that the marginal cost-average cost gap is narrowing, due largely to the recent stabilization in marginal fuel prices.

We believe that there is still a need for well-designed utility conservation programs, which will mitigate any recurrence of the price shocks of the last decade. Utility-financed conservation programs provide an important opportunity for ratepayers to understand and reduce their energy bills. We recognize that ratepayers may have limited information, and that financial

---

8 Extensive testimony was presented in this proceeding regarding methodologies for calculating Edison's avoided costs. Since the OIR 2 proceedings present a broader forum for consideration of this topic, the portions of the record in this proceeding which are relevant to avoided cost calculations have been incorporated into the record in A.82-04-044 et al., which address the utilities' long-run avoided cost methodologies. We defer decision on this matter to that proceeding.

constraints may further limit their ability and willingness to invest in energy conservation. A broadly-based utility energy conservation effort therefore has an inherent value as a means to insulate ratepayers somewhat from energy price increases by increasing the efficiency of their energy uses.

For these reasons, we will not reject any proposed conservation programs solely on the basis that they fail to met the nonparticipant test, as the test-year calculations in this record would present it.

However, three of Edison's conservation programs which meet the utility perspective test show program costs clearly beyond any reasonable range in which the marginal cost-average cost differential could lie, based on the information in Table VI-4: the Basic Audit Surveys, New Customer Booklet, and Conservation Planning Centers. The Basic Audit Surveys programs is not being funded, since Edison's RCS program which supersedes this program was recently approved in D.82-11-086.

In calculating the costs of energy savings shown in Table VI-4, Edison assumes that each customer receiving a New Customer Booklet will do the equivalent of unscrewing a 100-watt lightbulb, which yields a cost of 6.11¢/kWh saved. This crude assumption is insufficient grounds for denial of this program. However, we instruct Edison to reclassify the New Customer Booklet as a Public Awareness expense, since this more accurately portrays its function.

We will not disallow funding for the Conservation Planning Centers. However, we caution Edison to structure this new program carefully to maximize cost-effectiveness, and to monitor the Centers' performance carefully to allow evaluation of the energy savings realized.

Edison calculated the cost-effectiveness of its proposed load management programs shown in Table VI-5 from both the utility and the nonparticipant perspectives. For the utility perspective, the utility program costs (excluding incentive payments) are compared

to Edison's avoided capacity costs. The costs used in evaluation of load management programs from the nonparticipant perspective include both the utility program costs and any incentive payments. Cost-effectiveness from the societal perspective or the participant perspective was not quantified.

A number of uncertainties regarding both the costs and the benefits of load management programs make it impossible for us to reach definitive conclusions regarding the cost-effectiveness of Edison's load management programs at this time. Perhaps the greatest uncertainty surrounds the benefits, which Edison and staff assume are equal to Edison's "avoided costs." Final determination of the correct avoided cost methodologies and results is still pending in the OIR 2 proceedings. Further, we are not entirely convinced that use of avoided costs developed for generation sources is a correct method of evaluating the benefits of load management. We address this question further in Section VI.C.

Staff believes that cost-effectiveness of load management programs should be measured when a program is considered to be implemented as opposed to evaluating it under experimental or demonstration conditions. Consistent with this belief, staff recommends use of benefit-cost ratios calculated assuming project equipment and engineering costs are rate-based. Table VI-5 contains results based on both expensed and capitalized treatment and also results of a 1985 large implementation program.

We concur with staff that rate-base treatment of load management costs should be assumed in evaluating cost-effectiveness. Potential economies of scale associated with widespread implementation should also be considered. A number of Edison's load management programs do not meet the nonparticipant test, based on 1983 program costs and Edison's filed avoided capacity costs. However, the non-participant benefit-cost ratio in 1985 is greater than 1.0 for all programs, assuming Edison's representation of 1985 costs of a large program.

Staff points out that additional benefits such as reduced pollution and also additional costs such as any cost of shifting work schedules to off-peak hours need to be evaluated. We agree, if quantification of such elusive factors is possible.

Staff has recommended that Edison proceed with several load management programs at a slower pace than Edison has proposed. We agree that such caution may be warranted, and are reducing Edison's requested budget by 20%, as discussed in Section VI.A. We stress that Edison should allocate the approved funds to those programs which look most promising. Edison should maintain continuing evaluation of the cost-effectiveness of programs as more experience is gained and more accuracy is obtained in the estimation of system benefits and large-scale implementation costs, and should reallocate funds if need be.

C. Discussion of Programs

1. Regulatory and Management/Administrative Support

Subsequent sections discuss specific conservation and load management programs. Since we treat regulatory and management/administrative support funding consistently for all programs, we find it expedient to discuss these areas separately at this point.

For each major conservation and load management program category, Edison maintains a Regulatory Support category. In addition, Edison requests funding for one overall Management/Administrative Support effort. In these categories, staff has recommended that funding be cut in proportion to any reductions made in direct program expenses. Edison argues that support programs also include offset rate applications, OIIs, OIRs, and other state and regulatory requirements, and that no reductions should be made in these categories even if base rate programs are cut. Since we are not setting strict budgets for conservation and load management programs in this decision, Edison's management will have discretion to establish funding levels which it believes are needed for regulatory and management/administrative support programs.

The manner in which the Regulatory Support and Management/Administrative Support categories are delineated by Edison is troublesome. Regulatory Support is defined to include certain activities whose relationship to regulatory activities is tenuous at best. These activities include rate design, cost-effectiveness calculations, data collection and analysis, and price elasticity studies. On the other hand, Management/Administrative Support contains funds for certain activities which are clearly regulatory in nature, such as preparation of testimony, exhibits, and workpapers for NOIs, OIIs, general rate cases, and offset applications; coordination of response to data requests; and preparation of formal reports to state and federal regulatory agencies. This overlap makes it difficult to evaluate the magnitude and reasonableness of regulatory support and other support activities. We instruct Edison to clarify its accounting procedure by consolidating regulatory support activities to the extent feasible by the time of its next general rate case application.

2. Nonresidential Conservation Programs

The staff agrees to the level of funding requested by Edison. The only reduction staff recommends is due to the lower escalation rates which staff uses.

After review, we find that Edison's nonresidential programs appear to be well-reasoned and cost-effective. We agree with staff, however, that the Commercial/Industrial New Construction program, which is a test program designed to provide information to architects, engineers, and building contractors about energy-efficient building designs and methods, should be continued in 1984 only if 1983 results are promising.

We note also that Edison has proposed expenditures of $860,500 for Commercial/Industrial Support Activities, most of which is planned for advertisement and information brochures. While we will not specifically disallow any portion of this expense, we reiterate our policy which discourages non-program-specific advertising. Advertisements and brochures should be designed with this policy in mind.

3. Residential Conservation Programs

a. Residential New Construction

The staff recommends deletion of the $7,013,300 which Edison requests for this program, based on our action in D.82-04-068 issued April 8, 1982. Due to the anticipated implementation of new state residential building standards, in D.82-04-068 we did not adopt a proposed rule which would have mandated that utilities provide monetary incentives to builders who install certain conservation measures.

Edison agrees with staff that the $7,013,300 requested to fund incentives during 1983 is no longer required for that purpose. We note that implementation of the new building standards has been delayed. However, we still will not allow funding for the Residential New Construction program due to its high cost shown in Table VI-4.

Edison proposes that this funding be reallocated to its Residential Conservation Service (RCS) audit program. Funding for RCS is treated in the next section.

b. Residential Conservation Service

In this rate case, Edison requested funds for a residential Basic Audit Survey Efforts (BASE) program for 1983. Edison stated that it would transfer the funds to RCS audit activities if RCS is approved to supersede BASE. In later testimony, Edison now requests that the Commission authorize $12 million in base rates for RCS in place of the $5 million requested for BASE and the $7 million requested for the Residential New Construction program.

Edison filed A.61067 in November 1981, after its filing of this rate case, requesting approval of its proposed RCS program and of incremental funding for 1982 beyond that already authorized in base rates. Edison requested in A.61067 that RCS program costs beyond those included in 1982 base rates be tracked through its Conservation Load Management Adjustment Clause (CLMAC) balancing account and costs recovered through the Conservation Load Management Adjustment Billing Factor (CLMABF). By D.82-11-086 issued

November 17, 1982, we authorized the proposed RCS program, but denied any additional funding for the 1982 program.

If funding for 1983 RCS expenditures were not granted in this case, Edison would be required to file an offset application to receive 1983 funds for RCS. Given the recent decision in A.61067, we believe that this would be an unnecessary duplication of effort, both for Edison and for our staff. We will approve monies to allow RCS activities to continue into 1983.

Funding will be allowed through the CLMAC balancing account rather than through base rates as Edison has requested, due to the uncertainty regarding RCS audit costs pending issuance of the California Energy Commission (CEC) final rules. We are not convinced that RCS activities in 1983 will require $12 million. The record in A.61067 indicated that RCS costs per audit have been estimated as approximately $100 for Edison's demonstration program, $94 for Southern California Gas Company, and $65 for PG&E (D.82-11-086, p. 32). Staff believed that audits could possibly be performed for $50 each if they were greatly simplified. We will approve the $5 million requested for BASE, which will increase the CLMABF by 0.009¢/kWh. We note that the $8.9 million authorized in D.82-11-086 to be recovered through the CLMAC in 1983 for Edison's Residential Conservation Financing Program will also increase the CLMABF effective January 1, 1983. The new total rate will be 0.027¢/kWh. If additional funding for RCS is determined to be needed after the CEC's final rules for RCS are published, Edison may file an offset application later in 1983. We would anticipate that requests for additional 1983 costs and 1984 funds could be consolidated into a single offset application.

c. Conservation Corner and Conservation Planning Centers

Edison operates a Conservation Corner in the Puente Hills Shopping Center, which it plans to phase out in 1983. In its cost analyses, Edison estimates that the information disseminated by this center results in energy savings at a cost of 15.36¢/kWh. Operation of this program for six months in 1983 would cost $192,900. Due to

its high costs, we find that the Conservation Corner should be phased out as quickly as possible.

Edison also plans to establish one Conservation Planning Center in each of its five divisions. These Centers would help developers, builders, architects, and homeowners choose cost-effective conservation measures for new residential construction. This program would cost $351,800. Edison estimates that about 2,700 structures would be influenced by this program in 1983, and that the utility cost would be 6.11 cents per kWh saved.

If they are carefully focused toward new construction, the proposed experimental Conservation Planning Centers could provide a more useful service than general information programs such as the Conservation Corner. We will not disallow funds for this program despite its questionable cost-effectiveness. If Edison implements the program, we expect it to design the Conservation Centers and the accompanying program advertising carefully and to continue the program only if it proves successful.

4. Solar Programs

The staff and Edison are in agreement with respect to the requested 1983 funding level of $429,400 for programs within the Solar New Construction category, which include service agreements for solar water heating systems, cash rebates for heat pump installations, and workshops on passive solar building techniques. Edison classifies its heat pump programs in the solar category because they are also aimed at electric water heating customers.

Edison's proposed funding for the Solar Marketing program exceeds staff's estimate by $145,000. This reflects the staff's recommendation that no funding be authorized for two solar marketing programs: the solar test facility and solar submetering. The staff's position is that the solar demonstration program funding which was authorized in OII 42 already covers the costs of those programs. We agree with the staff position that the proposed programs have already been considered and have been provided for in OII 42. These two programs should not be funded through base rates.

Edison's proposed funding for its Solar Retrofit program exceeds the staff's estimate by $732,200. This difference results from the staff's recommended disallowance of rebates for solar retrofits to multifamily units and to residential homes occupied after January 29, 1980. The staff recommends disallowance of funding for these programs because OII 42 specifically limited Edison's participation to single-family units occupied before January 29, 1980 and because Edison was again denied funding for multifamily solar retrofits in 1981. The staff's position is well taken. If Edison wishes to pursue this issue further, it should do so in the annual OII 42 solar offset proceeding or in a future rate case if evaluation of the existing demonstration program shows that expansion would be worthwhile.

Staff recommends that Edison's proposed heat-pump water-heater programs for both new construction and for retrofit installations be limited to homes located in areas where natural gas supply is not available. We concur regarding the new construction program, but will allow the retrofit program to also be available to customers throughout Edison's service territory who are unable to use solar systems.

5. Public Awareness

Edison requests $1,835,000 for 1983 conservation-related public awareness expenditures. Public awareness includes such activities as energy seminars, exhibits, booklets, bill enclosures, news releases, and a speaker's bureau.

The staff recommends reducing Edison's proposed funding to $1,000,000. We agree with the staff's recommendation. As we stated in D.93887 with respect to PG&E, "...the need for conservation is clear to most ratepayers...". Therefore, we will allow only the reduced funding level recommended by the staff subject to the 20% cut we have made to all programs.

6. Advertising

The staff recommends reducing Edison's proposed funding for advertising from $1.5 million to $1.0 million. We will allow at most $1.0 million subject to the overall 20% cut, for the reason we stated in our discussion above with respect to public awareness.

We note that many of Edison's conservation and load management programs provide for program-specific promotional activities in addition to this funding requested for general advertising. In Exhibit 13 Edison describes a total conservation advertising budget in excess of $4 million. We stress our policy of discouraging nonessential advertising. In implementing the 20% budget cut we have made, Edison should reevaluate the need for each advertising dollar spent.

7. Conservation Measurements

Edison has proposed an extensive conservation measurements program requesting funding of $3,439,000 for 1983. It builds upon and extends research directives made in D.92549 in the last Edison general rate case. Staff has concluded that Edison has made a good faith effort to comply with these directives. Edison proposes to more than double its expenditures for measurements and to increase its measurements staff by two and one-half times. This expanded research effort would make Edison's measurements program the largest in the state.

As shown in Table VI-1, Edison and the staff differed with respect to the estimated costs of the various projects contained within the conservation measurements program. In its opening brief, Edison stated as follows: "However, after reviewing those differences in light of current projections of measurement requirements, Edison agrees with staff's recommended Measurement Program funding levels."

Staff has recommended the establishment of a $200,000 contingency fund to be used to satisfy future unanticipated research needs. Since we are giving Edison limited discretion to reallocate funds up to $2,500,000, we will not require such a contingency fund.

Staff has further recommended that Edison be required to submit quarterly reports which describe the progress of research conducted in the prior quarter and research planned for the near future. We will require such reports. The timing and format of the reports should be determined jointly by staff and Edison.

The measurements programs proposed by Edison and staff are meritorious. However, they tend to focus on conservation or load management programs in isolation. Evaluation of the interaction of these programs with the utility system presents some very complex measurement problems, but is needed in order to accurately determine the value of these programs.

In our review of Edison's conservation and load management programs in this rate case, we have pinpointed at least two areas where measurement research is needed beyond that planned by Edison.

We particularly agree with staff that a need exists to determine externality costs and benefits of conservation and load management programs, such as those due to environmental effects or reduction of oil imports.

The utility system savings associated with particular load management programs should also be more carefully measured. Edison and staff assume that this system savings is the same as the "avoided capacity cost" which is calculated for payment to small power producers. The vastly different operating characteristics of the two types of technology imply to us that the system avoided costs could also be quite different.

We instruct Edison to expand efforts in these two areas, either under its measurements program or elsewhere if Edison prefers to categorize them otherwise. In particular, Edison should refine its determination of costs avoided by load management programs in time to incorporate results in its next general rate case.

8. Nonresidential Load Management Programs

a. C/I Load Control Program

The commercial/industrial load control program include C/I air conditioning cyclers, air conditioning chillers, energy cooperatives, and interruptible load and customer computer dispatch arrangements.

The staff recommends downward adjustment of Edison's requested funding for this program by $438,800. This contested difference relates to two projects: the C/I air conditioning chiller project and the customer computer dispatch project.

The staff would reduce the number of C/I air conditioning chiller installations, as proposed by Edison, to 10. The staff bases this reduction on the premise that Edison's proposed increase from 10 installations in 1982 to 50 installations in 1983 is unrealistic. The staff also recommends reduction of the customer computer dispatch project on the basis that Edison's goal of 15 participants appears overly ambitious.

We will not decide the merits of staff's contentions. We reiterate our concerns that new programs be expanded carefully and in the most cost-effective manner possible. Edison's management should evaluate the proposed programs to determine whether information which may be needed to decide the cost-effectiveness of wide-spread implementation can be obtained with smaller programs.

Edison proposes a major expansion in 1983 of its C/I Air-Conditioning Cycling program. Edison already has cycling equipment installed and tested for 600 commercial and industrial customers and planned to add 250 new participants in 1982. The proposed 1983 expansion would entail the installation of 22,500 cycling devices on the air-conditioners of 5,350 new participants. Staff recommends adoption and expense treatment of Edison's requested expenditures of $4,933,000 for this program.

Due to the large scale of the proposed C/I Air Conditioning Cycling Program, we find that expense treatment is not proper. We have established precedents of rate basing such load management

expenditures for both PG&E and SDG&E, and will require that capital expenses of $3,589,000 for this program also be rate-based. Staff has recommended rate-base treatment for the residential air-conditioning cycling and DSS programs. We see no distinction among the three programs to warrant differing treatments for ratemaking purposes. Rate-base treatment will reduce 1983 revenue requirements by $2.9 million.

We expect Edison to maintain records regarding installations of air-conditioning cycling equipment which is rate-based. We are approving rate-base treatment with the expectation that load management programs will be implemented in a timely manner. Edison's activities in 1983 and 1984 in these areas will be examined carefully in the next general rate case.

b. <u>C/I Thermal Storage</u>

The staff recommends that Edison's requested funding level of $2,631,800 be cut by 50%, which would leave sufficient funding to support one-half of the installations Edison had projected for 1983, based upon the utility's proposal to pay a maximum incentive payment of $400 per kW.

Edison anticipates that $2,307,000 of the program budget would be paid to participants as grant incentives. The staff notes that the $400 per kW incentive represents a maximum incentive payment. We expect Edison to pay only the amount of the incentive necessary to stimulate customer response, and to maintain records on actual incentive payments made.

Edison proposes that the Thermal Storage incentive payments be considered as program costs. We will treat them in a manner consistent with that afforded other load management incentive payments, and allow recovery through rate design. If these payments are disbursed in a manner other than through a specific rate tariff, such payments will be treated for ERAM purposes as a reduction in the actual base revenue amounts calculated each month.

In general, incentive payments to customers in each customer class who participate in load management programs are treated as

"transfer payments" to the participants from nonparticipants in that class only, and are recovered through that class's rate design. We see no reason to treat these commercial/industrial incentive payments differently.

As noted previously, we allow recovery of $3,500,000 through rate design for load management incentive payments. Edison's management will have discretion to implement programs which require these incentives within the limitations we have established.

The rationale for treating incentives as transfer payments within a customer class deserves further analysis. At least some portion of the incentive payments is likely to be compensation for costs and inconvenience caused by program participation. The proper recovery method for incentive payments has not been examined in any depth in any proceeding before this Commission to date. We instruct both Edison and staff to address this issue in Edison's next rate case proceeding. In the interim, we will continue the present practice of recovery through rate design from the particular customer class affected.

c. New Load Management Equipment Evaluation

The staff recommends that Edison's requested funding for this program be reduced by $347,800. This reduction reflects a downward adjustment for evaluation of equipment not specified by Edison. We will leave this decision to Edison management.

9. Residential Load Management Programs

a. Demand Subscription Service and Residential Air Conditioning Cycling Programs

Edison originally requested approval of its proposed demand subscription service (DSS) program in this rate case. However, on August 2, 1982, Edison filed a separate application, A.82-08-10, for approval of DSS, providing further definition of the proposed program and changing it from a mandatory to a voluntary program. Edison anticipated that a decision on the merits of the proposed DSS program would be reached in A.82-08-10 prior to this rate case decision, and that funding could thus be authorized in today's rate case decision.

Hearings in A.82-08-10 were delayed to the extent that its decision date has slipped beyond today. Since funding was requested in this rate case rather than in that proceeding, ALJ Mallory issued a ruling on October 22, 1982 which consolidates the two cases and reopens A.61138 for the express purpose of receiving further testimony on the DSS program. We will reject the request of both Edison and staff that the expenditures proposed for DSS in 1983 be approved in this decision and set aside pending a decision in A.82-08-10. We will establish program funding, if warranted, for the DSS program in a later decision in A.61138 concurrent with our anticipated decision in A.82-08-10.

Because of the above facts, the issues concerning DSS raised by CPRA, TURN, Leisure World, and CVAG have either become moot or address program details which are more appropriately reviewed in the separate application.

No disagreement exists between the staff and Edison regarding the nonhardware expenses of the residential air conditioning cycling (ACC) program. Originally, however, Edison proposed that hardware costs for this program be expensed rather than capitalized. Pursuant to the stipulation it made during oral argument, Edison now accepts the staff's recommendation to capitalize the hardware costs of the ACC program.

We note that in A.82-08-10 which has been consolidated with this rate case, Edison has stated that it now plans to install only 10,000 residential ACC units in 1983 rather than the 32,000 requested in this proceeding. For this reason, we will reduce the expense portion of Edison's request from $1,948,500 to $600,000 and the amount of equipment costs rate based for this program in 1983 from $5,192,000 to $1,622,000.

CVAG also made several allegations regarding Edison's policy with respect to load management in general. These allegations are basically that Edison has not looked at purchased power as an alternative to load management. This allegation is not supported by the record.

b. Swimming Pool Program

Edison's requested funding for this program exceeds staff's estimate by $1,210,800. This difference reflects staff's disagreement with Edison's proposal to regulate swimming pool pumps by means of radio-controlled devices in lieu of compliance with CEC's Load Management Standards program and enforcement of Edison's tariff Rule 14.1. The staff has concluded that Edison has not made concentrated ongoing efforts to enforce that rule. In this regard, the staff has recommended an expense allowance of $83,000 to enforce Rule 14.1. We believe the staff's position to be well taken; therefore, we will not allow implementation of the swimming pool direct load control program.

c. Residential New Equipment Evaluation

The contested difference for this program of $1,428,100 results from the staff's method of estimating costs using a trend of five years' recorded expenses, with additional allowances for new equipment installation, a computer system, and load research and testing.

We will not make specific adjustments to this program, nor approve the additional attrition allowance which staff recommends. The decision regarding appropriate funding for this program will be left to Edison's management, within the limitations we have imposed.

d. Load Management Information

The proposed information budget of $1,660,000 includes four load management billing inserts and a "Give Your Appliances the Afternoon Off" advertising program. Staff reduced the expenses in this category by the $83,000 it recommended be transferred to the swimming pool project for enforcement of Rule 14.1.

We will not make specific cuts to this program. We remind Edison, however, of our policies regarding advertising expenditures.

D. Other Conservation Issues

1. Conservation Voltage Regulation Program

Funding for Edison's on-going Conservation Voltage Regulation (CVR) program is included as a distribution expense in

FERC Account 583 and Account 584. However, Energy Conservation Branch staff analyzed this program in its conservation testimony. For that reason, we also discuss it in the conservation section of this decision.

Edison requests the following amounts for its CVR program:

	1983	1984
Expense	$ 860,000	$ 674,000
Capital	4,434,000	3,044,000
Total	$5,294,000	$3,718,000

Staff notes that Edison is making good progress on its CVR program, and has complied with previous Commission decisions regarding this program. Staff recommends that Edison be allowed the expenses and capital expenditures requested. We concur.

2. Definition of Conservation Potential

In its opening brief the staff states:

> "Definition of energy potential is important because it determines the amount of potential which is identified and affects whether activities in current programs can be compared with the potential that is identified."

Substantial disagreements have arisen between the staff and utilities as to the appropriate definition. In Exhibit 124, the staff recommends that we adopt the following definition:

> "Conservation potential is the difference between a 'Private Market Effect' sales forecast and a 'Maximum Conservation' forecast, as shown in Figure 1 of Exhibit 124. If adopted, any departures from the definition should require staff approval."

We have examined Exhibit 124. We find that staff has developed some good ideas. However, there is insufficient guidance in Exhibit 124 regarding quantification of the "Private Market Effect" and "Maximum Conservation" scenarios. We encourage staff and the utilities to continue refinement of both the definition of conservation potential and a methodology to calculate conservation potential.

3. Proposal of California Community and Junior College Association

CCJCA represents all 197 two-year community colleges in the state, 38 of which are served by Edison. CCJCA requests that the Commission adopt the following proposals which would use the particular attributes and characteristics of community colleges as electricity consumers to achieve valuable conservation objectives:

"(1) With CPUC approval, Edison should allocate a minimum of $280,000 of its 1983 conservation budget and an equal proportion of its 1984 conservation budget, exclusively to assisting community colleges identify and implement additional conservation, load management and alternatives.

"(2) With CPUC approval, Edison should conduct an intense field program to assist all colleges served on the TOU-8 schedule to shift demand from on-peak to off-peak periods. This will cause more efficient use of Edison's capacity resources.

"(3) With CPUC approval, Edison should make avoided capacity cost payments, based upon marginal capacity costs, to colleges who are able to contract for long-term reliable reductions and/or shifts in demand. This will provide the appropriate and equitable incentive for the colleges to make all cost-effective investments.

"(4) With CPUC approval, Edison should provide direct capacity cost financing assistance for conservation and alternative energy projects that the colleges cannot finance alone. A loan fund containing one million dollars for each of the years 1983 and 1984 should be initially established for this purpose and used to fund conservation and load management projects. This will replace the rapidly disappearing sources of financing that the colleges have historically used, and assure that all cost-effective projects are implemented. Based upon the outcome of the efforts under our first proposal, the CPUC and Edison should

> consider increasing the size of the fund to provide cogeneration and alternative generation financing."

In the event that the Commission does not adopt any or all of the four proposals, CCJCA urges the Commission to consider establishing a new rate class for community colleges "based on the evidence that the colleges as a group are making much greater strides in achieving conservation than other Edison customers in their respective rate classes, and by doing so, are substantially lowering Edison's cost to serve them." CCJCA indicated, however, that it has not established a detailed proposal for this action at this time.

CCJCA believes that if its recommendations were implemented, they could provide 1983 savings on the order of $2,700,000 for the colleges and $3,710,000 for Edison. According to CCJCA, the $1,000,000 difference would accrue to other ratepayers and ultimately reduce their rates.

While we applaud the efforts of CCJCA to promote conservation, we decline to adopt CCJCA's proposals at this time. In this decision we are authorizing substantial funding for a number of conservation and load management programs for nonresidential customers in which CCJCA can participate. These programs include energy audits, monetary incentives to builders who install conservation measures, and incentives to encourage air conditioner cycling or thermal storage.

The proposals suggested by CCJCA unfortunately lack sufficient detail to enable us to determine their cost-effectiveness not only to CCJCA but to all ratepayers. We are reluctant to approve CCJCA's requested funding from Edison for CCJCA's proposals until an analysis of their cost-effectiveness is made. On the other hand, the CCJCA proposal has brought to our attention a significant potential for conservation and load shifting among community college customers. We encourage Edison to explore this potential in cooperation with CCJCA.

VII. Staff-Recommended Penalties

Staff recommends that the Commission penalize Edison for failure to make reasonable efforts to promote cogeneration, wind and auxiliary/emergency generation during 1980 and 1981. The recommendation includes separate penalties for each resource. Table VII-1 shows the recommended penalties and their impact on Edison's operating results.

TABLE VII-1
EFFECTS OF PROPOSED PENALTIES
Test Year 1983

Resource	Penalty On: Rate of Return %	Penalty On: Return on Equity * %	Impact Of Penalty On: Net Operating Income (Millions of Dollars)	Impact Of Penalty On: Juris. Rev. Requirement (Millions of Dollars)
Cogeneration	0.20	0.48	9.49	19.42
Wind	0.10	0.24	4.75	9.72
Aux/Emergency	0.02	0.05	0.95	1.94
Total	0.32	0.76	15.19	31.08

*Assumes a capital structure with 42% common equity.

A. Proposed Penalty/Reward System

Under the staff proposal, as outlined in Exhibit 50, the penalties would be applied by reducing the rate of return adopted for the 1983 test year. At the end of calendar year 1983, Edison's performance would be reevaluated and the individual penalties would be removed or continued depending whether Edison's performance had met the goals recommended in Exhibit 50. Staff proposes the establishment of a penalty/reward system on an ongoing basis. Table VII-2 is a reproduction of Table 6-1 of Exhibit 50. The table describes, in broad terms, the proposed penalty/reward system.

TABLE VII-2

GOALS FOR COGENERATION, SPP, WIND, AND AUXILIARY/EMERGENCY GENERATION PROPOSED FOR EDISON, 1982-1984

Program	Goals, per year, for CYs 1982, 1983, and 1984*	Maximum Basis Point Penalty/Reward
Cogeneration**	200 MW	20
Wind Parks	100 MW	10
Auxuliary/Emergency Generation	20 MW	2

*Executed contracts.

**Includes cogeneration, small wind/solar projects under 100 kW, biomass and refuse-derived fuels, and small hydro under 30 MW.

Other than the foregoing table and figure, Exhibit 50 provides little explanation or detail as to how the proposed penalty/reward system was devised or how it would be administered. However, the following extract from the staff's opening brief may be of some help in understanding the penalty/reward plan:

> "Penalties/rewards be set for performance which fails/exceeds a goal by more than 10%. At the end of each calendar year, the utility reports to the Commission the contracts which it has executed in that year; based on this submission, the Commission sets the penalty/reward to apply to the utility's return in the subsequent year. A limit is set on the maximum penalty/reward; this maximum is reached when performance fails/exceeds a goal by 20% or greater. It seems fair that the rewards which the utility can earn should be equal to the penalties to which it is exposed. The recommended maximum of 20 basis points for cogeneration follows a precedent set with PG&E; the maximums for wind parks and auxiliary/emergency generation were scaled by comparing the goals for these programs with the 200 MW per year goal for cogeneration. The staff considers the 20 basis points for cogeneration to be a good starting point, because in the case of PG&E the penalty of that magnitude triggered a significant improvement in PG&E's performance regarding cogeneration."

We perceive that the penalty/reward proposal, as introduced into this record, is little more than a conceptual outline. Both the target goals of each program and the corresponding penalties and rewards were not well-founded in this record. Nor is the procedure sufficiently developed to provide us with an adequate basis for implementing it in this proceeding. Accordingly, we will not adopt such a plan for Edison at this time. Instead, we will consider the penalty recommendations of the staff separately and apart from such a plan.

Staff's recommendations are based on an analysis of Edison's effort to identify cogeneration and small power production (SPP) resources within its service area, Edison's level of productivity in signing letters of intent and contracts with Qualifying Facilities (QFs) during 1980 and 1981, and Edison's willingness to offer full avoided cost payments to QFs as required by Commission decisions. As discussed below, we find that only the third area of analysis can justify the imposition of a penalty on Edison. We will address each of these areas.

B. Potential for Cogeneration, Wind, and Auxiliary/Emergency Generation

Staff asserts that Edison failed to assess adequately the cogeneration potential within its service area. This assertion is based on D.89711 dated December 12, 1978 in A.57602, an Edison general rate case. That decision required Edison to perform a study of cogeneration potential within its service area. The record shows that Edison made the required study. The staff contends that because of the intervening years, Edison should have updated the study. Edison, however, was under no requirement to do so, although Edison did, in fact, update its study beginning in 1981. The record shows that Edison was never advised that the results of its assessment of cogeneration potential were inadequate.

Staff nevertheless contends that Edison has underestimated the cogeneration potential within its service area by a factor of two or more. This contention is based on a comparison with the

cogeneration potential identified for PG&E. Staff, however, made no independent study or survey to evaluate Edison's stated goals or to verify that Edison's service area is similar to PG&E's.

Similarly, staff made no independent analysis of the potential for developing additional auxiliary/emergency generation within Edison's area. With respect to the development of wind, staff did not take issue with Edison's identification of potential wind resources.

Based on the evidence in this record, we cannot find that Edison failed to identify adequately the potential for cogeneration, wind, or auxiliary/emergency generation.

C. Level of Productivity

Staff concludes that Edison's level of productivity in signing letters of intent and contracts with QFs is inadequate when compared to PG&E's level of productivity. With respect to cogeneration staff also concludes that Edison did not comply with the directive set forth in D.92549, Edison's test year 1981 general rate case:

> "Edison should apply all possible vigor and imagination to its cogeneration program with the goal of bringing the maximum amount of cogeneration on-line in the shortest possible time."

D.92549 did not establish quantifiable goals by which to measure Edison's productivity. Moreover, D.92549 quoted the staff as stating that it considered Edison's cogeneration program to have been effective.

With respect to wind and auxiliary/emergency generation, neither staff nor the Commission has set quantifiable goals for Edison to meet within a certain time frame. In October of 1980, Edison announced a goal of 560 MW of wind by 1990 which was neither questioned nor modified by staff or the Commission. The auxiliary/emergency generation program which Edison offers is a pilot program and in Edison's view is markedly different from PG&E's full-scale program. Staff did not dispute this.

Edison, in its opening brief, argues that it would "...be profoundly unfair to adopt, ex post facto, a numeric standard in megawatts and hold Edison liable for not attaining that later established goal." Edison asserts that it has never been placed on notice as to what specific amount of cogeneration, wind, and auxiliary/emergency generation it would be expected to sign in order to avoid penalty.

We agree with Edison that it would be unfair to penalize the company for failure to meet targets of which it was not aware. We are unclear as to why staff had not informed Edison of its dissatisfaction in October of 1980 when Edison announced its goals for the development of alternative and renewable resources. We therefore decline to base a penalty on this ground.

Nevertheless, we are concerned that Edison's level of productivity in signing QF contracts or letters of intent is substantially less than PG&E's. Although Edison criticized staff's failure to demonstrate the reasonableness of staff's comparison to PG&E, Edison offered no explanation of the wide disparity in levels of productivity.

We think that the answer lies largely in Edison's refusal to offer full avoided cost payments to QFs.

D. Willingness to Offer Full Avoided Cost Payments to QFs

While the assertions discussed thus far appear to be unsupported, the evidence regarding Edison's avoided cost pricing policies under contracts entered into with QFs is largely unrefuted.

Staff presented extensive testimony regarding Edison's bargaining position in negotiating contracts with wind developers. Staff observes that Edison has been extremely reluctant to sign standard contracts at full avoided cost. Instead, Edison persuades developers to sign non-standard contracts at less than full avoided cost in return for Edison's offers of sale or lease of Edison-owned land, assistance in the environmental permitting process, or easing of interconnection requirements. In staff's view, Edison's offers are used to exact substantial discounts from avoided cost which are

beyond the value of Edison's offers of assistance. Staff's conclusion is based on its review of confidential financial analyses which Edison has performed on executed contracts and signed letters of intent with wind developers.

Staff further testified that when Edison did offer the standard avoided cost contract, the contract contained termination, renegotiation, and conditional pricing provisions which were very unfavorable to QFs. Staff maintains that Edison included these clauses to steer QFs away from the standard contract and towards a negotiated offer at well below Edison's published avoided cost. Notably, none of these clauses are included in Edison's standard offers after May of 1982, or in Edison's signed nonstandard contracts.

Staff began receiving informal complaints from cogenerators and other QFs in October of 1981. These complaints alleged that Edison refused to pay full avoided cost or enter into buy-sell arrangements, and that Edison was inflexible during negotiations with QFs.

Under cross-examination Edison agreed that since April of 1981 it had been its policy not to make standard offers to QFs based on full avoided cost. The policy was reflected implicitly in Edison's May 1981 standard offer which had deleted a clause in its prior offer which provided that "payments [to QFs] for the total output should, in every case, be at least equal to the avoided cost of energy."

Staff concludes that Edison's pricing policies during 1980 and 1981 necessarily had a chilling effect on the development of QF resources within Edison's service area and were contrary to the express policies set forth by this Commission.

We have been exploring the opportunities for utility encouragement of cogeneration and other alternative and renewable resources since 1976. In Report to Legislature, D.85559, C.9004, March 16, 1976, 79 C.P.U.C. 513 we stated that "PG&E, Edison, and SDG&E should be required to report on the status of (a) any presently

operating waste heat electric generating plants and (b) any utilization of waste heat from their own utility generating facilities for industrial or commercial purposes, together with plans for an expanded program."

On January 10, 1978, we issued Resolution E-1738 which stated, and ordered, inter alia:

> "Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas and Electric Company have installed, negotiated for and are presently developing this valuable resource but insuffîcent progress has been reported since our Decision No. 85559 dated March 16, 1976, in Case No. 9804.
>
> "3. Within 30 days after the date of this resolution, PG&E, SCE, and SDG&E shall provide other specific rate proposals to enhance cogeneration, including revisions to standby rates.
>
> "4. PG&E, SCE and SDG&E fully identify long-term cogeneration potential and provide time frames for bringing these sources on line. Within 15 days after the effective date of this order, PG&E, SCE and SDG&E shall file status reports on cogeneration projects being considered as of January 1, 1978. This report should be updated quarterly.
>
> "5. Within 60 days after the date of this resolution, PG&E, SCE and SDG&E should submit guidelines covering the price and conditions for the purchase of energy and capacity from cogeneration facilities owned by others.
>
> "6. Within 60 days after the date of this resolution, PG&E, SCE and SDG&E should submit a report on guidelines for development of utility owned cogeneration facilities."

As a result of this Resolution, new interruptible rate schedules were filed, rates for standby service were substantially reduced, the utilities began to file quarterly reports on cogeneration potential, and the utilities were ordered to submit guidelines covering the prices and conditions for the purchase of energy and capacity from facilities owned by others, as well as prices and conditions for the development of utility-owned cogeneration projects.

Almost simultaneously and independently, the Federal Energy Regulatory Commission (FERC) issued its discussion paper in Docket No. RM79-55. The FERC's paper discussed energy and capacity payments, the "share the benefits" approach, and presented an argument for full marginal cost payment. FERC issued its proposed rules in October 1979, endorsing the full avoided cost payment concept for cogenerators and SPPs.

On December 19, 1979, we issued D.91109 in OII 26 which endorsed the full avoided cost standard and authorized PG&E to file price offers within 45 days to purchase electricity produced by cogeneration and nonconventional fuel at PG&E's full avoided cost. PG&E mailed its first offer to over 11,000 interested parties on February 4, 1980. Two weeks later, on February 19, FERC published its final rules, pursuant to Section 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA). The FERC rules not only supported this Commission's findings, but endorsed the avoided cost principles.

On March 4, 1980, in Resolution E-1872, we ordered as follows:

"IT IS ORDERED THAT:

"1. The following electric utilities shall file an interim schedule of prices to be paid small power producers and cogenerators including proposed contract terms and provisions for purchase in conformance with the economic policies announced in Decision No. 91109 issued December 19, 1979.

Southern California Edison Company
San Diego Gas and Electric Company
Pacific Power and Light Company
Sierra Pacific Power Company
CP National

"2. Each electric utility shall mail copies of their schedules of full avoided costs for energy and capacity and proposed contract terms to all existing and identified potential small power producers and cogenerators."

We may conclude from all of the foregoing that Edison has been under a duty since January 10, 1978, at the earliest, and since March 4, 1980, at the latest, to exercise its best efforts to pursue and develop cogeneration and SPP resources using avoided cost principles.

We agree with our staff that Edison's pricing policies with respect to QFs have been contrary to the clear intent of our past decisions that utilities offer full avoided cost payments to QFs when so requested. By letter dated December 21, 1981, President Bryson again informed Edison of the Commission's policy. This letter was prompted by reports from QFs that Edison refused to make full avoided cost offers.

To our great dissatisfaction Edison continued its pricing policies into 1982, as indicated by Edison's response to our decision in OIR 2 issued in January. In D.82-04-071 we suspended the initial standard offers which were filed in accordance with the OIR 2 decision. In particular, we stated that:

> "Edison's initial offers are not based on avoided cost. Inasmuch as we do not concur with Edison's position that standard offers based on avoided costs are not required nor appropriate, Edison should be required to amend its initial offers to base them on avoided costs."

We construe Edison's actions in early 1982 as evidencing a continuing pattern of disregard for the Commission's avoided cost policy of the past three years.

Based on the foregoing, we conclude that a penalty is justified. In our view Edison's pricing policies during 1980 and 1981, and even through early 1982, undoubtedly impeded the development of QF resources. We are disappointed that among the large utilities Edison alone has chosen to adopt such policies. We further observe that these policies undermine Edison's stated goal to bring on line 2,100 MW of alternative and renewable resources by 1990.

We therefore will assess a penalty which is the revenue equivalent of 10 basis points on Edison's return on equity for 1983

and 1984. This represents an impact on gross operating revenue of about $3.9 million in 1983 and $4.1 million in 1984, for a total two-year penalty of $8.0 million. We have adjusted the gross revenue requirement authorized today by this amount. In 1979, we assessed a 20 basis point penalty on return on equity against PG&E in both the test year and the attrition year in D.91107. We believe that Edison's actions justify a penalty which is approximately one-half of the penalty imposed upon PG&E.

E. Brokerage Fee

In response to D.82-01-103 in OIR 2, the staff proposed a methodology, in its testimony on Edison's cogeneration and small power programs, for paying a brokerage fee to utilities in their role as intermediaries between QFs and ratepayers.

Staff proposes to establish a brokerage fee based on the utility's role as a retailer of QF power. The proposal would give the utility an incremental return on the various services which the utility provides to the QF. These services include transmission, distribution, billing of customers, and administrative and general services. The brokerage fee would equal the value of these services plus a return equal to the utility's percentage return on total revenues. The fee would be expressed in cents per kWh and would not be tied to a certain percentage of avoided cost. Payment of the fee would be by the QF. An illustration of the method is contained in Exhibit 50.

In D.82-01-103 we requested comments on the concept of a brokerage fee. Only our staff has responded and has offered a specific proposal. For some reason neither Edison or any other party addressed the general concept or the staff proposal.

We think that the concept of a brokerage fee has merit and will stimulate and accelerate development of the QF market. However, in light of the absence of response by other parties, we are reluctant at this time to adopt a specific proposal. We are particularly interested in receiving the input of QFs and other utilities to the staff proposal, and again invite any interested party to submit its own proposal.

In order to preserve the issue, we have incorporated the staff proposal into the Report and Request for Comments that we have issued on long-run avoided cost offers. By so doing, QFs and all other electric utilities will have an opportunity to comment and present alternate proposals for a brokerage fee. We strongly urge all interested parties to participate actively.

VIII. Rate Base

A. General

Table VIII-1 presents a comparison of Edison's and the staff's figures for test year rate base according to its principal components. Table VIII-1 shows the contested difference by issues between Edison's estimate of rate base and the staff's. Edison's test period rate base estimate exceeds the staff's by about $49.5 million, which excludes consideration of FERC fuel costs.

TABLE VIII-1

SYSTEM RATE BASE*

Test Year 1983

Items at Issue	Amount Edison Exceeds Staff
	$M
SONGS I Sleeving**	45,240
Plant Budget**	(10,687)
Nuclear Fuel Disposal	(2,296)
Working Cash Allowance	14,512
Negative Net Salvage	(3,842)
Deferred Taxes for 1982	6,916
Removal Cost	2,507
Other	(2,875)
	49,475

(Red Figure)

*Does not include FERC fuel.

**Includes reserve deductions and deferred tax effects.

In its opening brief, TURN urged that SONGS Unit 1 be removed from rate base. There is no evidentiary support in this record to justify such an adjustment to rate base.

B. SONGS Unit 1 Sleeving

As discussed in Section IV.O, we have chosen to expense instead of capitalize the cost of sleeving SONGS Unit 1 as extraordinary maintenance. There is no further rate base issue with regard to this facility.

C. Plant Budget

The staff based its estimate on the utility's third-quarter plant budget including certain adjustments for operative construction work in progress (CWIP) made by Edison.

The total effect on rate base of the plant budget differences between Edison and the staff is $10.7 million, the staff figure being the higher. Of this difference only $0.7 million relates to electric plant itself. The balance is comprised of $0.3 million in deferred taxes and $9.7 million in depreciation reserve. The difference thus relates largely to depreciation reserve.

We have adopted staff's figure for the plant budget, since it reflects later data.

D. Nuclear Fuel Disposal

The adopted rate base treatment of this item is consistent with our adopted ratemaking treatment of this item, as discussed in Section IV.I.

E. Reserve Deductions

1. Depreciation Reserve

The difference in staff's and Edison's estimates of depreciation reserve is related to the following: (1) Edison's use of somewhat higher depreciation rates for certain plant accounts; (2) the capitalization of SONGS Unit 1 sleeving costs by Edison; and (3) the different plant budgets used by Edison and the staff. The issues relating to these differences are discussed in other parts of this opinion. Our adopted estimate of depreciation reserve is consistent with our treatment of these items.

2. Deferred Taxes

The difference in staff's and Edison's deferred tax reserve is due to (1) Edison's requested inclusion of SONGS Unit 1 sleeving costs in rate base; (2) different plant budget estimates; (3) differences in the normalization requirements for income taxes and the tax treatment of spent nuclear fuel and amortization of uranium and plutonium salvage; (4) differences in depreciation rates; and (5) differences in the manner of computation of the deferred tax reserve.

The adopted amount for the deferred tax reserve is consistent with our treatment of income taxes and depreciation expenses, as discussed in Section IV.

F. Working Cash Allowance

Our adopted working cash allowance reflects those expenses adopted elsewhere in this decision. We have also adopted the staff lag day estimates, which are consistent with our treatment of lag days in prior decisions. Included in our adopted working cash allowance is the change in lag days for federal income taxes due to the TEFRA, as discussed elsewhere in this decision.

IX. Rate of Return

A. Cost of Capital

Financial presentations were made by Edison, the staff, the Federal Executive Agencies (FEA), Coachella Valley Association of Governments (CVAG), and the California Association of Utility Shareholders (CAUS). Table IX-1 presents a comparison of their recommendations for return on rate base and return on common equity.

TABLE IX-1

COMPARISON OF RECOMMENDED RETURNS ON RATE BASE AND COMMON EQUITY

	Return on Average Rate Base		Return on Common Equity
	1983	1984	1983-84
	%	%	%
Edison	13.87	14.06	19.00
Staff	13.02-13.23	13.15-13.36	17.00-17.50
FEA	12.62	12.76	16.00
CAUS	*	*	19.50
CVAG	12.66-12.87	12.79-13.00	16.16-16.66

*No Recommendation.

Edison assumed the following capital structure in determining its test year 1983 and attrition year 1984 costs of capital: long-term debt, 46.0%; preferred stock, 12.0%; and common equity, 42.0%. The staff, FEA, and CVAG also used this capital structure. CAUS, however, made no specific assumption as to capital structure in its showing.

Edison originally proposed the adoption of year-end 1983 cost of capital for test year 1983, and it included $12 million in test year revenue requirement in its showing to cover 1984 financial

attrition. Edison subsequently stipulated to the use of average-year cost of capital for 1983 and 1984 as recommended by the staff and FEA. The stipulation resulted in the withdrawal of the $12 million revenue requirement.

B. Embedded Cost of Senior Capital

Edison, the staff, and FEA presented evidence on the costs of debt and preferred stock, but CVAG and CAUS did not. Table IX-2 presents a comparison of the embedded costs of debt and preferred stock as recommended by the parties.

TABLE IX-2

COMPARISON OF COST OF SENIOR CAPITAL

	1983		1984
	Year-End %	Average %	Average %
Embedded Debt Cost			
Edison	10.75	10.53	11.03
Staff	10.69	10.52	10.76
FEA	*	10.56	10.82
Embedded Preferred Stock Cost			
Edison	8.87	8.65	8.88
Staff	8.80	8.63	8.81
FEA	*	8.63	8.81

*No Recommendation.

The differences shown above in the embedded debt costs and embedded preferred stock costs result from Edison assuming generally higher debt and preferred stock costs than selected by the staff and FEA in 1982, 1983, and 1984, as shown in Table IX-3.

TABLE IX-3

COMPARISON OF SENIOR CAPITAL COSTS FOR 1982 THROUGH 1984

	Debt Cost			Preferred Stock Cost		
	1982 %	1983 %	1984 %	1982 %	1983 %	1984 %
Edison	15.0	15.0	15.0	14.0	14.0	14.0
Staff	15.0	14.0	13.0	14.0	13.0	*
FEA	*	15.0	14.0	*	13.6	12.6

*No Recommendation.

1. Edison's Position

It is Edison's position that it would not be reasonable to assume a decline in interest rates during the expected two-year span that this base-rate decision will be in effect. Edison asserts that the basic economic conditions underlying its interest rate forecasts have not changed and that there is no sign of a slowing in the foreseeable future of the upward pressure on interest rates. Accordingly, Edison continues to adhere to its estimates for 1983 through 1984 of 15% for the cost of debt and 14% for preferred stock, i.e., the figures that it postulated in 1981 when the application was being prepared. Edison contends that the current interest rate decline will prove to be a short-term affair and that the Commission should take a longer term view in setting its rates through the end of 1984.

To minimize the cost of new debt, Edison states that it has used many forms of innovative financing, including private placements of bonds and preferred stock, leveraged preferred stock, nuclear fuel lease arrangements, project financing, pollution-control bonds, and the issuance of Eurobonds. The evidence shows that Edison has, in fact, kept its interest costs below those of the 20 largest electric utilities in the United States despite its heavy dependence on capital markets for funds in recent years.

2. Staff's Position

The staff's figures for embedded debt costs for 1982, 1983, and 1984 were derived from an analysis of planned issuances and retirements and were based on historical data and DRI interest rate forecasts. The staff's estimates of the amount of long-term financing through 1984 agree with Edison's projections; however, the staff's cost estimates are at different rates than assumed by the utility. Edison forecasts that its cost of new debt will average 15% through 1984, whereas the staff assumes falling interest rates as follows: 1982, 15%; 1983, 14%; and 1984, 13%. Similarly, Edison assumes a 14% rate for preferred stock through 1983, with no new preferred stock being issued in 1984. The staff again assumes a falling rate; its dividend projections for new preferred stock are 14% in 1982 and 13% in 1983.

3. FEA's Position

In making his estimates of debt costs, the FEA's expert witness on cost of capital reviewed not only the forecasts of DRI, but a recent forecast by Wharton Econometric Forecasting Associates (Wharton). He adopted the average of the forecasts, and he estimated rates for the cost of new debt of 15% for 1983 and 14% for 1984 using the staff's projected financing schedule. He adopted cost rates for preferred stock of 13.6% for 1983 and 12.6% for 1984, which are consistent with his estimated costs for long-term debt.

C. Return on Equity

Edison, the staff, FEA, CAUS, and CVAG made recommendations on the return on common equity that should be allowed in the test year. Their presentations relied upon the following methods of supporting their respective positions: risk premium analysis, interest coverage, and discounted cash flow. None of the parties made recommendations based upon the comparable earnings test, although the staff and FEA, as well as Edison, considered comparisons with other utilities.

1. Edison's Position

Edison asserts that its capital, cash flow, and return requirements have increased as a result of current conditions in the business environment. These conditions include double-digit inflation, volatile and, at times, constricted capital markets, and structural changes in the supply of electrical service, as well as regulatory delays, constraints, and directives. Because of these conditions and the inability of rate relief to keep pace with the needs of utilities, Edison views itself, and the electric utility industry as a whole, as now being riskier than in the past.

According to Edison, the financial health of a utility is measured by whether it can maintain a double-A bond rating and sell new common stock at or above book value. Edison contends that, in order for it to meet the test of these two measurements, this Commission must: change its regulatory emphasis toward improving earnings and cash flow; focus its attention on the low level of revenue producing assets relative to total capital; and modify policies which do not allow sufficient cash flow on the revenue producing assets that are included in rate base.

To maintain its financial integrity, Edison states that it requires (1) internal cash generation of at least 40%, (2) pretax interest coverage of at least three times, and (3) a higher ratio of cash earnings to total earnings, i.e., improved quality of earnings.

Edison points out that its proportion of internally generated funds has declined from 59% in 1976 to 18% in 1980. Edison attributes this decline to increased capital requirements, increased AFUDC, and inadequate rate relief. To maintain a 40% level of internally generated funds through 1984, Edison states that it will need the 19.0% return on equity it has requested in this proceeding.

As evidence that its return on common equity has been inadequate, Edison recites that since 1972, the price-to-book cost ratio for Edison common stock has been below unity and that since

1971 industrial equities have outperformed Edison and the 20 largest electric utilities. In Edison's view, it has not been able to earn its authorized rate of return because this Commission has not recognized adequate level of O&M expenses in the determination of its revenue requirement. Edison states that it was able to earn near its authorized return on equity in 1981 only because its management made extensive deferrals of maintenance activities.

Edison relied upon risk-premium[9] analysis in support of its requested 19% return on common equity. Edison based its risk-premium showing on work done by Ibbotson and Sinquefield (I&S), as well as its own analysis of double-A utility bonds and Edison common stock since 1971. The I&S analysis purports to demonstrate that a risk premium of from 400 to 600 basis points above bond yields is required for common stock returns based on I&S's analysis of historical data. Relating this risk premium to Edison's forecast of the cost of debt in 1983 and 1984 would produce a required return on equity in the range of 19 to 21%.

Edison's own analysis of the period 1971 to 1981 showed similar results, indicating that the risk premium required to attract investors to Edison's common stock is in the range of 476 to 597 basis points. This range of the risk premium would also appear to support a return on common equity of from 19 to 21%.

Edison also relied on interest coverage requirements in support of its position. Using its estimates of capital structure and embedded costs of debt of 10.74% in 1983 and 11.03% in 1984 and

---

[9] The rationale underlying the risk-premium concept is that the common stock investor is a residual holder, and his investment is riskier than bonds or preferred stock; hence, risk premium is the increased yield necessary to offset this greater risk.

assuming an interest coverage of 2.80 times after taxes,[10] Edison computes its required return on common equity at 18.64% in 1983 and 19.24% in 1984. According to Edison's calculations, 2.80 was the average after-taxes interest coverage allowed by the Commission in Edison's last five general rate cases. Edison has also calculated that the average risk premium allowed in these five decisions was 633 basis points.

2. Staff's Position

The staff believes that the Commission should not place primary reliance on mechanical approaches, such as a risk-premium analysis, that are based on past recorded data. In the staff's view, the risk-premium analysis completely overlooks what risks investors anticipate in the future test year and attrition year. As the staff notes in its opening brief, all of the data of record, including that of Edison and CAUS, discloses that the so-called risk premium varies greatly from one year to the next. The staff contends that for this reason Edison and CAUS were compelled to use averages of five past years, and that if the latest recorded years only were used, there would not be sufficient risk premium to support Edison's claimed equity allowance. The staff believes that Edison attaches unwarranted weight to the risk-premium approach. The staff points out that current financial theory questions the basic assumption of a risk premium of equity over debt.

---

[10] There is no fixed relationship between before taxes and after taxes interest coverage, although Edison's witness stated that historically the difference has been about 0.20; thus, Edison construes 3.00 times before taxes to be equivalent to 2.80 times after tax. The 19.0% return on common equity would produce interest coverages after taxes of 2.83 in 1983 and 2.78 in 1984 using the assumed capital structure.

In the staff view, the significant considerations to which the Commission should give greatest weight are the very favorable financial and operating characteristics of Edison and the significant regulatory responses of this Commission which ensure Edison's opportunity to earn its authorized equity allowance in the test and attrition years. If these factors are taken into consideration, the staff believes that its recommmendation would provide Edison with an adequate allowance to maintain these favorable characteristics and continue to enjoy investor favor.

On the thesis that earnings calculations are not a matter of precision and that a range of reasonableness exists, the staff recommends 17.0 to 17.5% return on common equity. In making this recommendation, the staff states that it took a number of factors into consideration; among them were the following:

1. Edison's sources of financing. The internal sources of funds have been declining since 1977 due to the substantial increase in AFUDC over the last five years. With the completion of SONGS Units 2 and 3 and their anticipated inclusion in rate base, this increase in AFUDC as a percentage of earnings will be dramatically reduced in 1983 and years following.

2. Comparable earnings analysis. The staff made comparisons with 20 Aa bond-rated electric and combination utilities and with the 20 largest electric utilities regardless of bond ratings.

3. Interest coverage requirements. The staff recommended rate of return would provide approximately 2.71 times after-tax coverage. The staff notes that this coverage is comparable with the coverages included in our five most recent decisions setting Edison's rate of return and that it should permit Edison to meet its current fixed charges and to maintain the Aa bond rating that it has held over the period covered by these decisions.

4. Risk-premium analysis. The staff believes that its recommendation is consistent with its historical analysis and that it would provide adequate compensation for any additional risks. The staff analysis indicates that the premium required by Edison investors over Aa bonds has fluctuated from 9.43% in 1976 to a low of 1.37% in 1980. Noting that there is no one fixed premium over the period, the staff used a premium of 300 to 500 basis points to indicate an investor-required return on equity of 16.50 to 18.50% for 1983 and 1984.

5. Discounted cash flow (DCF)[11] analysis. Using a 10-year history recorded data for Edison, the staff calculated an expected dividend yield of 10% to 10.5% and an expected dividend growth rate of 7.0% to 7.5%, which resulted in a range of 17% to 18% as the investors' expected discount rate for Edison. This was compared against average historical discount rates developed for the two groups of electric utilities used by the staff in its analyses.

---

[11] The DCF method is based upon a theory which suggests that the market price of a common stock is equal to the present value of the sum of future dividends and the price at which the stock would be sold in the future. According to this theory, the investor discounts the anticipated future cash flow, which equals the sum of future dividends and the eventual sale price of the stock, at a capitalization rate which equates this present cash value to the market price of the stock and which approximates the cost of common equity. This capitalization rate is mathematically equal to the dividend yield plus the anticipated future growth rate in dividends per share if certain assumptions are made, the most important being the growth of dividends at a constant rate.

3. FEA's Position

The FEA relied primarily on a DCF methodology to estimate Edison's cost of equity capital on the basis that it is the preferred means of estimating the cost of common equity at the present time.

FEA's witness estimated the growth rate of dividends for Edison by multiplying the expected retention rate times the expected return on common equity. He reviewed Edison's historical retention rates and achieved returns on common equity and determined that a retention rate of 30% was a reasonable expectation. Using a price of $30 per share and a growth rate of 4.5% to 5% with a current dividend of $3.24 per share, he calculated an expected dividend yield in the range of 11.29% to 11.34%. Under the DCF methodology, this dividend yield plus the assumed growth rate would produce a cost of equity of 15.79% to 16.34%.

To validate this result, the FEA's witness extended his DCF analysis to a group of comparable electric utilities which had bond ratings of Aa. For this group of companies, a 200-day moving average price as of March 5, 1982, produced an expected dividend yield of 12.01% based upon an average growth rate of 4.16%. By adding the expected dividend yield of 12.01% to the growth rate of 4.16%, he obtained an average estimated cost of common equity of 16.17%. The FEA's witness also assessed the relative riskiness of Edison relative to this group of comparable electric utilities. Based upon measures of financial and business risks, he determined that Edison would be judged to be comparable in risks to the group of Aa-rated electric utilities. Taking into consideration trends in allowed rates of return over time and risk differences among companies, he determined that an allowed rate of return of 16% would be reasonable for Edison.

While FEA agrees conceptually with the staff's use of the DCF model, it believes that the staff's forecast of growth rates by the use of data over historical periods is not as accurate as its own approach. FEA points out that its witness estimated Edison's growth

based on a methodology used by security analysts, i.e., its estimate is based on the percentage of retained earnings and the rate of return on book equity. FEA regards this approach to be more accurate than the staff's because historical data suggests that Edison's growth in earnings and dividends has not been smooth and that the relevant growth rate is the expected, not historical, growth rate. FEA points out that the staff's higher estimate of the growth rate leads to a higher recommended return on common equity using the staff DCF model. FEA believes that the staff DCF results would enable Edison to earn an excessive return at the expense of the ratepayers.

FEA takes the position that an estimate of the cost of equity based upon a historical risk premium developed using data from a past period of time, when interest rates were markedly different than those we presently face, produces an unreliable estimate of the current cost of common equity. FEA recommends, therefore, that the Commission look to other methods of estimating the cost of common equity at the present time.

4. CAUS's Position

CAUS is a nonprofit organization with over 9,000 members, each of whom is a stockholder in one or more major California utilities. CAUS limited its participation to the rate of return aspects of this proceeding. It is CAUS's position that since Edison's stock has sold below book value, it has failed to meet the capital attraction test of the U.S. Supreme Court.

CAUS supports a 19.5% return on equity, which is somewhat higher than the 19.0% being requested by the utility itself. CAUS's position on this point is that the Commission has the duty to ensure that the utility has adequate revenues to fulfill its public utility obligation and that there is no law forbidding the Commission from giving a rate increase larger than the utility has asked for.

The witness appearing on behalf of CAUS used an approach relying primarily on a risk-premium analysis based on (1) a comparison of Edison's earnings to Aa bond yields and (2) a comparison of return on equity to Aa bond yields. He developed a historical average risk premium (1977 to 1981) presumably because the currently derived risk premium is considerably narrower and would not support the 19.5% return on equity that CAUS recommends. From the 1977-1981 comparison, CAUS's witness concludes that a risk premium of 400 to 500 basis points is required to allow Edison to sell its common stock at book value.

5. CVAG's Position

CVAG presented a witness who recommended a return on equity of from 16.16% to 16.66% and rates of return of 12.66% to 12.87% for 1983 and 12.79% to 13% for 1984. CVAG bases its recommendation on the argument that Edison's favorable financial condition, as well as comparisons with industrials and other electric utilities, warrants no greater increase in return on common equity than that granted in D.92549 in Edison's last general rate case. No recognized or substantive methodology was advanced by CVAG to support this approach.

D. Adopted Rate of Return

There is no issue with respect to the utility's capital structure for the test year 1983 and attrition year 1984; therefore, we will adopt the following capital structure which was used by Edison and the other parties: long-term debt, 46.0%; preferred stock, 12.0%; and common equity, 42.0%.

Because of the stipulation Edison made during oral argument, there is no longer an issue respecting the use of average-year versus end-of-year cost of capital. We will adopt average-year cost of capital.

Both staff and Edison agreed that actual long-term debt financings made during 1982 should be recognized in determining the weighted cost of debt component of the capital structure for 1983 and

1984. We concur and will reflect Edison's actual financings in 1982. We observe that Edison's actual 1982 financing exceeds the amount of financing in 1982 estimated in the rate case by $125 million. Accordingly, we will reduce the 1983 estimate of financing by a like amount so that the total financing projected by Edison over the period 1982 through 1984 remains constant.

During 1982 Edison issued long-term indebtedness in April, July, October, and November. Over this span the effective interest rate to Edison has declined from 16.33% for $125 million of Series TT bonds issued on April 14, 1982 to 12.16% for $200 million of 30-year mortgage bonds issued most recently on November 4, 1982. The decline in interest rates which Edison has experienced is reflective of the overall trend in interest rates which has occurred since the submission of this proceeding. It is doubtful that interest rates during 1983 will approach the levels projected by the parties during the hearings. We believe that a cost of 13% is a more reasonable estimate of Edison's cost of financing during 1983. For 1984 we will adopt 13% as reasonable based on our staff's recommendation.

With respect to the cost of preferred stock, we consider reasonable and we will adopt 14.0% for 1982 as recommended by both Edison and the staff. For 1983, we regard the 14.0% forecast by Edison and the 13.6% forecast by FEA to be too high; we will therefore adopt the 13.0% recommended by the staff. No cost will be adopted for 1984 since the record shows that a preferred stock offering is not likely to be made.

We have considered carefully all of the extensive evidence in this record regarding the cost of common equity. The <u>Hope</u> and <u>Bluefield</u> decisions of the U.S. Supreme Court have established that a reasonable rate of return should be sufficient to enable a utility to maintain its financial integrity, to attract capital, and to compensate investors for the risks assumed.

As we stated in D.93892 (SDG&E), the rate of return which will satisfy these tests depends on many circumstances. The determination of a reasonable return on equity is necessarily a matter of judgment and cannot be reduced to a fixed formula. Each case must be decided after considering many variables, such as the cost of money, the capital structure of the utility in comparison with similar utilities, and interest coverage ratios. In addition, risk factors specific to the utility must be considered. We have provided for an electric revenue adjustment mechanism. This mechanism reduces the risk to the company that its earnings may be eroded by a reduction in electric sales below the adopted sales levels. We have also provided an attrition allowance which will provide Edison a reasonable opportunity to earn the authorized rate of return in attrition year 1984.

We take cognizance of the decline in interest rates which has occurred since the submission of this proceeding. There is now little indication that interest rates will approach levels during 1983 which were forecasted during the hearing process. In light of this factor, Edison's cost of financing should be lower than Edison originally anticipated.

After weighing all of the above factors, we find that a return on common equity of 16% is just and reasonable. As shown in Table IX-4, the 16.00% return on common equity will yield an adopted rate of return on rate base of 12.55% for 1983 and 12.65% for 1984.

TABLE IX-4

ADOPTED RATE OF RETURN
Test Year 1983
Attrition Year 1984

Component	Capital Ratio %	Cost Factor	Weighted Cost %
Average Year 1983			
Long-Term Debt	46	10.42	4.79
Preferred Stock	12	8.63	1.04
Common Stock Equity	42	16.00	6.72
Total	100		12.55
Average Year 1984			
Long-Term Debt	46	10.59	4.87
Preferred Stock	12	8.81	1.06
Common Stock	42	16.00	6.72
Total	100		12.65

E. Annual Energy Rate (AER) Adjustment

In D.92496 the Commission provided for adjustment of electric base rates to exclude fuel oil inventory as a base rate item and permitted the recovery of carrying costs associated with fuel oil inventory in the AER. D.93628 provides that the AER be revised whenever the Commission adopts a change in the authorized rate of return. Since we have authorized a 12.55% rate of return in this order, it is appropriate to revise the AER, which was last established in D.82-04-119, to reflect this change in rate of return. The AER will be revised from .00236 $/kWh to .00253 $/kWh to produce $137,647,000 in total AER revenues, or $9,177,000 in additional revenues. The additional revenue requirement was calculated by multiplying the CPUC jurisdictional fuel oil inventory adopted in D.82-04-119 of $430,333,000 by the new authorized rate of return of 12.55% and by application of the new adopted franchise and uncollectible factors of 0.800% and 0.2125%, respectively.

X. Summary of Results of Operations

A. General

Although other parties participated in the results of operations phase of this proceeding, only Edison and the staff presented complete results of operations estimates upon which to determine the base-rate revenue requirements of the utility for the test year 1983 and the attrition year 1984. The estimates of Edison and the staff, as finalized at the time of submission, are summarized in Table X-1. The adopted results shown in Table X-2 for California jurisdictional operations exclude ECAC revenues from operating revenues (i.e., reflect base-rate revenues only) and exclude energy costs recoverable through ECAC from operating expenses.

B. Jurisdictional Cost Allocation

For purposes of this rate proceeding, a cost-of-service analysis based on average cost is necessary to determine the allocation of adopted 1983 expenses and facilities between the jurisdictions of this Commission and the FERC. No party took exception to Edison's method of allocating costs and return between the two jurisdictions. Also, the staff adopted Edison's method of jurisdictional cost allocation in the preparation of its showing. Since no issue is presented with respect to this subject, we have adopted Edison's methodology for purposes of this decision. Thus, differences among the estimates of Edison, the staff, and those we have adopted for the test year do not arise through the jurisdictional allocation procedures; rather, the differences reflect divergent estimates of cost before allocation.

TABLE X-1

Southern California Edison Company

SUMMARY OF EARNINGS

Test Year 1983

(Dollars in Thousands)

Item	Present Rates Staff	Present Rates Utility	Proposed Rates Staff	Proposed Rates Utility
Operating Revenues	$1,615,788	$1,615,788	$2,921,462	$2,921,462
Operating Expenses				
Total Fuel Expense	44,955	45,912	44,955	45,912
Total Power Prod. - Other	291,243	322,480	291,243	322,480
Total Transmission Expense	55,094	56,712	55,094	56,712
Total Distribution Expense	140,265	142,903	140,265	142,903
Total Customer Acct. Expense	68,484	73,942	71,258	76,716
Total Cust. Svc. & Informt'l	66,036	81,768	66,036	81,768
Total Admin. & Gen. Expense	202,017	224,725	212,441	235,148
Subtotal	868,094	948,442	881,292	961,639
Total Depreciation Expense	284,712	298,003	284,712	298,003
Taxes Other Than on Income	69,543	72,396	69,543	72,396
State Corp. Franchise Tax	13,758	5,501	134,806	114,933
Federal Income Tax	75,235	38,845	614,092	535,349
Total Operating Expenses	1,311,342	1,363,187	1,984,445	1,982,320
Net Operating Revenues Adjusted	304,446	252,601	937,017	939,142
Rate Base	4,975,331	5,075,775	4,975,331	5,075,775
Rate of Return	6.12%	4.98%	18.83%	18.50%

Southern California Edison Company

Adopted Summary of Earnings

Test Year 1983 at Present and Authorized Rates
(000's Omitted)

Item	Present Rates: Total Department	Present Rates: CPUC Jurisdictional	Authorized Rates Before Penalty CPUC Jurisdictional	Penalty	Authorized Rates After Penalty CPUC Jurisdictional
Operating Revenues	$1,615,788	$1,590,652	$2,161,346	$(3,936)	$2,157,410
Operating Expenses					
Total Fuel Expense	36,632	34,208	34,208	-	34,208
Total Power Production - Other	294,128	272,833	272,833	-	272,833
Total Transmission	54,029	40,095	40,095	-	40,095
Total Distribution	138,992	138,895	138,895	-	138,895
Total Customer Accounts	68,853	68,814	70,027	(9)	70,018
Total Customer Service and Info.	45,549	45,549	45,549	-	45,549
Total Admin. & General	198,324	191,175	195,741	(32)	195,709
Subtotal	836,507	791,569	797,348	(41)	797,307
Total Depreciation Expense	284,501	271,528	271,528	-	271,528
Taxes Other Than Income	68,972	66,096	66,096	-	66,096
State Corp. Franchise Tax	17,713	22,043	74,951	(365)	79,586
Federal Income Tax	95,288	113,822	349,345	(1,624)	347,721
Total Operating Expenses	1,302,981	1,265,058	1,559,268	(2,030)	1,557,238
Net Operating Revenues	312,807	325,594	602,078	(1,906)	600,172
Net Nucl. Fuel Disp. Rev. Adj.	(3,957)	(3,673)	(3,673)	-	(3,673)
Net Op. Rev. Adjusted	308,850	321,921	598,405	(1,906)	596,499
Rate Base	4,995,818	4,770,007	4,770,007	-	4,770,007
Net Nucl. Fuel Disp. Adj.	(1,978)	(1,836)	(1,836)	-	(1,836)
Rate Base Adjusted	4,993,840	4,768,171	4,768,171	-	4,768,171
Rate of Return	6.18%	6.75%	12.55%	(.04)%	12.51%

(Red Figure)

C. Net-to-Gross Multiplier

The staff and Edison disagree as to the proper method for determining the net-to-gross multiplier. The staff calculated its net-to-gross multiplier by first subtracting uncollectible expense from total revenue and then multiplying the net by the franchise fee percentage to determine franchise fee requirements. Edison, on the other hand, did not subtract uncollectible expense from total revenue before calculating the franchise fee requirements.

The record shows that Edison's methodology is the proper means of calculating the net-to-gross multiplier because the several taxing authorities use gross receipts as the base for determining the franchise fees charged the utility. No downward adjustment is made for uncollectible expense. Further, although some customers do not pay their bills, their omission is compensated for by increasing Edison's revenue requirement to account for uncollectible expense, thus increasing the gross receipts base used by the taxing authorities. It appears then, that franchise fee requirements are determined on the assumption that all customers pay their bills or, looked at another way, on the basis that Edison's revenue equals its revenue requirement with no subtraction of uncollectible expense. Accordingly, it would be inappropriate for us to make such a subtraction. Therefore, we will adopt Edison's method of making the net-to-gross multiplier calculation.

XI. Attrition

A. Background

Under our Regulatory Lag Plan, major utilities are not permitted, in the ordinary course of events, to file applications for increased base rates more often than once every two years. As a consequence, it is necessary to fix base rates on sales and cost estimates prepared some 18 months prior to the beginning of the test

year. The recent history of the electric utility industry has been a continuum of cost increases accompanied by low rates of sales growth. Under these circumstances, base rates, fixed on the basis of test year projections, will not reasonably reflect conditions in the attrition year, the year following the test year.

In recognition of this problem we have undertaken to overcome the effects of high rates of inflation and low growth of sales through the mechanism of an allowance for attrition of earnings. In Edison's last application for increased base rates, A.59351, Edison proposed a single level of rates for the test year 1981 and the attrition year 1982 which would have offset the effects of attrition by a higher level of charges throughout the two-year period. However, in deciding that proceeding, we adopted another approach. To offset operational attrition during 1982, we established a stepped-rate procedure, and to compensate Edison for financial attrition during 1982 we used year-end rather than average year cost of capital for 1981.

In D.93887 and D.93892, supra, in PG&E's and SDG&E's latest general rate cases, we adopted an attrition rate adjustment (ARA) procedure which we found necessary to provide the utilities a reasonable opportunity to earn their authorized rates of return in the attrition year. The decisions identify those components of attrition which could be quantified when the decisions were issued, and they call for the indexing of those ARA components which could not reasonably be determined at that time. The adopted procedures provide for the utilities to file advice letter showings in October of the test year. The advice letters are to include a showing upon which, if justified, the Commission can base the findings necessary to increase rates to provide the additional revenue requirement of the attrition year. The evidence in this record shows that a similar procedure would be appropriate for purposes of establishing Edison's

base rates for the attrition year 1984. We are structuring our ARA mechanism in a manner which will avoid the necessity of holding a further hearing.

Attrition is comprised of four elements: (1) operating costs consisting of labor and nonlabor expenses, (2) capital related costs, (3) financial elements, and (4) uncollectibles and franchise fees related to the other three components. Under our adopted procedure in this rate case, only the second and third elements are quantifiable at this time in terms of a 1984 dollar amount. Therefore, we will not adopt a total attrition allowance for 1984 at this time. Instead, we will adopt a procedure that, to the extent appropriate in this proceeding, tracks the ARA process established for PG&E and SDG&E, wherein Edison will file an advice letter in the latter part of 1983 quantifying its additional revenue requirement proposal for the year 1984. This procedure will provide for the establishment of updated escalation rates for operating expenses in the fall of 1983.

B. Attrition Allowance Issues

It is the staff's position, with which Edison now agrees, that the total 1984 attrition allowance should be split into an indexed component and a fixed component. The indexed component would consist of an amount adopted for 1983 test year labor- and nonlabor-related expenses to which would later be applied an indexing formula to determine attrition year labor- and nonlabor-related expenses. Other attrition items, including depreciation, ad valorem taxes, income taxes, and return on rate base would be fixed amounts to be determined in this decision.

Edison and the staff disagree on the base amount of 1983 test year labor- and nonlabor-related expenses to which the indexing formula should be applied to determine the 1984 attrition allowance. They disagree also on the dollar amount and the method for determining the fixed component of the attrition allowance. The

labor-related base amount differences arise from different estimates for (1) pensions and benefits, (2) labor-related activity expenses, and (3) escalation rates. The nonlabor-related base amount issues result from (1) the staff's exclusion of property insurance, (2) different estimates for nonlabor-related expenses, and (3) differences caused by the escalation rates. The fixed component differences are largely the result of (1) the staff's use of historical data to project plant additions versus Edison's method of using a plant budget and (2) the staff's nonrecognition of working capital changes between the test year and the attrition year.

The following is a discussion of the differences between Edison and staff which involve their respective attrition allowance proposals and which are not addressed in other sections of this opinion.

1. Property Insurance Expense

The staff proposal does not consider property insurance expense in calculating the attrition allowance. It assumes that insurance premiums are the same for the test year and the attrition year. Edison points out, however, that the premiums associated with property insurance are renegotiated annually and reflect increasing plant costs. We agree with Edison that property insurance expense is not fixed and that it should be considered in the attrition allowance calculation. Adoption of the staff's proposal would result in Edison experiencing a shortfall in 1984 revenues of approximately $0.4 million.

2. Plant Additions

In calculating 1984 attrition-year plant additions, the staff used a seven-year historical average unit cost calculation of net plant additions (excluding major generation plant additions) divided by the added number of customers. The staff multiplied the resulting average unit cost per customer by its 1983-1984 customer growth estimate to derive 1984 plant additions related to growth. To

this figure the staff added estimated 1984 major generation plant additions. The staff contends that the seven-year historical-cost calculation smooths out the fluctuations in plant additions. Although Edison proposes a thorough review of capital expenditures, the staff does not believe that this is necessary or appropriate. The staff points out that the review would be based on resource plans which are subject to change. The staff advocates adoption of its methodology because it is founded on historical data and because it would not burden the limited staff resources available for this purpose.

Edison used its quarterly plant budget to estimate plant additions for adjusting rate base for purposes of determining 1984 attrition. Edison's approach would, in effect, require calculation of an additional set of test year results. While we believe that a full review of additional rate base items is the most accurate way of estimating 1984 results, we believe the staff's approach to be more practical and entirely adequate under the circumstances. We are adopting the staff's methodology, and, by so doing, we will also be resolving the corollary issues concerning attrition year 1984 depreciation, taxes, and return.

3. Working Capital

The largest difference between Edison and the staff in their attrition year 1984 rate base recommendations relates to working capital, which includes the components of fuel stock (fuel oil and miscellaneous), materials and supplies, and working cash allowance. The staff used the same amount of working capital for the attrition year 1984 as it did for the test year 1983, thereby excluding any changes in these components from consideration in the determination of attrition allowance. While the staff points out that a reasonable working cash allowance would be difficult to determine two years in advance, inflationary increases can certainly be expected to impact fuel stock, as well as materials and supplies.

Further, the staff included in its attrition determination changes in ad valorem taxes, income taxes, and nonlabor expenses, all of which affect the working cash allowance.

While we see the point of Edison's working cash proposal, to adopt it could necessitate a hearing process to evaluate the various working capital elements. As we stated in D.93887, our purpose in establishing an ARA procedure is to avoid unnecessary hearings; hence, the ARA procedure should be essentially mechanical. Although our adopted attrition allowance will not include an increase in working capital, we would, in future rate cases, consider proposals for the development of a simplified working capital allowance for the attrition year.

4. Financial Attrition

As previously discussed Edison originally proposed the use of year-end cost of capital to determine the 1983 test year revenue requirement. If year-end cost of capital were to be used, the 1983 revenue requirement would be increased by $12 million and no financial attrition component would need to be included in the attrition allowance recommendation. The staff, on the other hand, recommends that average cost of capital be used to determine the 1983 test year revenue requirement and also recommends that financial attrition amounting to approximately $6.0 million be included in the attrition allowance for 1984.

Edison now agrees with the staff recommendation to use average cost of capital for determining 1983 test year revenue requirement, provided a financial attrition component of approximately $11.3 million is allowed for 1984. The divergence of the staff and Edison figures for financial attrition is the result of their different recommendations on rate of return and rate base, as well as different treatment of the interest deduction for increased 1984 debt costs. Edison reflected this deduction in the income tax calculation which is in the fixed component of attrition. If Edison

had included the interest deduction in the financial attrition component as did staff, its financial attrition recommendation would have been approximately $8.1 million lower. However, the fixed component of attrition, which includes income tax expense, would have been higher by $8.1 million thereby offsetting the financial attrition reduction.

C. Adopted Attrition Rate Adjustment Procedure

1. Advice Letter Procedure

Our adopted attrition rate adjustment (ARA) procedure will not consider changes in sales and revenue levels because our adopted ERAM will compensate for such changes. The labor and nonlabor costs which we adopt for test year 1983 will be adjusted to reflect the most current rate of inflation in 1983 and then be escalated by appropriate estimates of inflation factors as discussed in the following paragraphs on indexing. We will not adopt a growth factor; instead, we will postulate that any growth or increase in activity levels will be offset by increased productivity and efficiency.

The order will provide that Edison may make an advice letter filing, no later than October 31, 1983, showing the additional revenue requirement calculated for the attrition year 1984. The revenue requirement will be determined in accordance with the following procedure, summarized in Appendix E, using figures reflected in, or compatible with, the adopted results of operations for 1983 shown in Table X-2.

2. Labor and Nonlabor Expenses

Our premise for establishing an indexing formula for developing attrition year labor and nonlabor expenses is that we should use the most current estimates of inflation for 1984 in calculating the attrition allowance. Consistent with this premise, the 1983 expense base upon which we project 1984 expenses should also reflect the most up-to-date information regarding inflation for 1982 and 1983. Failure to adjust the expense base might otherwise lead to over- or underestimates of reasonable expenses in 1984.

We therefore will adjust the labor and nonlabor expense base adopted in this decision for 1983, which are given in Appendix E, to reflect the actual inflation which occurs in 1982 and the most current 1983 annual escalation rates as projected by DRI in its fall 1983 forecast. We will apply the following indexing formula:

$$\text{Attrition Allowance} = \left(A \times \frac{B}{C} \times D\right)^{*} - A\left(1-\frac{B}{C}\right)$$

A = The 1983 expense base subject to escalation as adopted in this decision (CPUC jurisdictional amount).

B = The compounded factor of (one plus the 1982 escalation rate) multiplied by (one plus the 1983 escalation rate), developed from the fall 1983 DRI forecast.

C = The compounded factor of (one plus the 1982 escalation rate) multiplied by (one plus the 1983 escalation rate), adopted in this decision.

D = The 1984 escalation rate developed from the fall 1983 DRI forecast.

*Appropriate uncollectible and franchise factors shall be included.

In determining the labor expense component of attrition, Terms B and D will be based on the fall 1983 DRI projections of the Consumer Price Index (Urban) of the applicable years. For the nonlabor expense component of attrition, Terms B and D will be based on the fall 1983 DRI projections of our adopted modified producer price index and consistent with the weighting developed in Section IV.C of this opinion.

Our adopted labor base includes labor-related pensions and benefits. Our adopted nonlabor base will exclude those items which are not subject to nonlabor escalation, including labor-related pensions and benefits and amortized expenses.

3. Capital-Related Costs

The capital-related costs treated in this section include ad valorem taxes, income taxes, and depreciation expenses, as well as

rate base effects. A comparison of the Edison, staff, and adopted amounts for these capital-related costs is presented in Table XI-1.

The differences in attrition year amounts for these items are due to the differences in: (1) estimating incremental rate base growth from 1983 test year to 1984 attrition year and (2) converting that growth to a revenue requirement level.

Edison's method is based on its construction budget and estimates of other rate base components as shown in its exhibits in this case. The method develops an estimated $270,712,000 increase in rate base between 1983 and 1984.

The staff's method is based on an estimate of a seven-year historical average of plant, excluding major additions, added per customer. This amount was modified to reflect major additons expected in 1984. The staff did not include other rate base components such as working cash. Our adopted attrition allowance recognizes the bases adopted for test year 1983. We will not adopt the staff's recommendation that a $260,000 attrition year allowance be given for a computer lease, as discussed in Section VI.C.

TABLE XI-1

AMOUNTS AT ISSUE
CAPITAL-RELATED ATTRITION

	Revenue Requirement Calculation		
	Edison $M	Staff $M	Adopted $M
Depreciation	47,400	42,249	42,249
Ad Valorem Taxes	5,095	3,524	3,524
Income Taxes	(11,786)	(10,469)	(16,915)
Return	63,666	42,210	38,970
Total Capital Related	104,375	77,514	67,828
CPUC Jurisdictional Subtotal	99,647	74,002	64,762
Computer Lease (Load Management)		260	-
Tax Equity and Fiscal Responsibility Act			655
CPUC Jurisdictional Total			65,417

4. <u>Financial Attrition</u>

During the course of the proceedings, Edison stipulated to the use of average-year cost of capital, as recommended by the staff, and in Section IX of this opinion we adopted the staff's recommendation. If we had adopted the year-end cost of capital approach originally proposed by Edison, there would be no requirement for a 1984 financial attrition allowance. The adoption of an average-year approach, however, necessitates an allowance for financial attrition. Table XI-2 provides the detail of the differences in financial attrition determinations on an average-year cost of capital basis.

TABLE XI-2

FINANCIAL ATTRITION

	Change in Cost of Capital 1983 to 1984		1984 CPUC-Juris. Rate Base $M		Net-to-Gross Multiplier		Financial Attrition $M
Edison	.19%	x	5,067,825	x	1.1766	=	11,329
Staff	.13%	x	4,942,059	x	1.1724	=	7,532
Adopted	.10%	x	4,948,978	x	1.2210	=	6,043

5. Uncollectibles and Franchise Fees

The attrition allowance for uncollectibles and franchise fees shall be determined by the following formula:

$$\text{Attrition Allowance} = \frac{100\ S}{100\ F}; \text{ where}$$

S = The sum of the CPUC jurisdictional labor base net attrition and the CPUC jurisdictional nonlabor base net attrition, as determined in paragraph 2 above.

F = The factor 1.0102295, which is the percentage increase in attrition required to cover uncollectibles and franchise fees.

XII. Pricing of Electricity

A. Test Year Marginal Cost

1. Commission Policy

a. Marginal Cost vs. Embedded Cost

The issue of whether this Commission would use marginal cost or embedded cost in electric rate design was last argued, discussed, and decided in D.92549 in Edison's test year 1981 general rate case. In this proceeding no new arguments were offered which would cause us to alter our policy, i.e., once the jurisdictional revenue requirement has been determined, we will rely on marginal cost as the principal determinant in the pricing of electricity.

In D.92549, as modified by D.92817,[12] we stated as follows:

> "As we have in other recent electric rate increase proceedings, we conclude that cost recovery by customer groups should, in general, be based on marginal cost concepts as recommended by Edison and others. In arriving at this conclusion we have used as a goal our often stated policy of adopting electric rates which encourage conservation, defined in Decision No. 85559 in Case No. 9804 as follows:
>
> "'1. The term conservation of electricity encompasses any one or any combination of the following elements:
>
> "'a. The reduction in wasteful kilowatt-hour usage of electricity.
>
> "'b. The overall reduction of kilowatt-hour usage of electricity.
>
> "'c. The reduction of peak demands upon electric utility systems.
>
> "'Conservation in the sense of efficient allocation of electricity will be the keystone on the rate structure.'

---

[12] D.92817 dated March 17, 1981 in A.59351, modified certain findings of facts in D.92549 and denied petitions for rehearing filed by CMA and CIEC.

"Marginal costs, because they tend to reflect the true cost of a customer's decision to limit or increase conservation, are more likely to send these clear and appropriate pricing signals than would rates based upon embedded costs."

This decision will reaffirm the following findings of fact which we made in D.92549:

"12. Marginal costs...provided the acceptable approach to allocating costs recovery among customer groups because they provide a clear pricing signal relating to a customer's conservation measures and are in keeping with PURPA standards.

* * *

"26. Embedded cost of service reflects historical construction costs and depreciation of existing plant which are not relevant to current costs of meeting changing demand of electric service.

"27. Embedded cost of service, although a factor to be considered in setting rates, is not an appropriate measure for determining the conservation impact of a particular rate design.

"28. It is equitable that changes in electric rates for each major customer group reflect the cost to the utility of furnishing the last increment of additional system supply.

"29. Directing rates for marginal usage by each major customer group toward the cost to the

> utility of furnishing an
> additional unit of system
> supply will provide appropriate
> signals to customers regarding
> consumption and will provide
> the appropriate incentive for
> concervation."

b. Marginal Cost Methodology

On March 3, 1981, we issued D.92749 in OII 67, which was an investigation into the generic methodology for the determination of marginal costs. The staff report adopted by that decision was the product of joint meetings with regulatory agencies, the major California utilities, and representatives of the private sector. In D.92749, we established a general methodology for the determination of marginal costs for a variety of purposes, including rate design, the pricing of alternative generation, and determining the cost-effectiveness of conservation/load management programs.

In this section, we will confine ourselves to the two uses for marginal cost in rate design: (1) marginal cost as the basis for determining the appropriate allocation of the jurisdictional revenue requirement among Edison's customer groups and (2) marginal cost as the basis of setting rate levels in the design of Edison's tariffs.

In D.93887, in PG&E's test year 1982 general rate case, we enunciated our policy regarding the proper methodology for determining marginal costs for purposes of allocation of costs to customer groups and rate design. We held that short-run marginal costs should be used for both purposes.

In the short-run methodology we adopted in D.93887, marginal costs have two components: (1) the energy component and (2) the generation shortage component. Marginal transmission and distribution costs are excluded. The generation component of marginal costs is based upon the concept of "shortage costs" which is

intended to represent the rationing premium that must be added to the marginal energy cost to maintain a reasonable level of reliability. Because of methodological and practical problems inherent in the direct calculation of a shortage cost, we adopt a "proxy", or substitute, for the shortage cost consisting of a combustion turbine (CT). We then determine the annual cost of the CT and allocate it to costing periods, i.e., on-peak, mid-peak, and off-peak in the summer and in the winter. The shortage cost and energy cost are combined by customer groups and the costing periods and then used to determine the marginal cost revenues by customer groups.

2. Positions of the Parties on Marginal Costs

Both Edison and the staff (the only parties who made complete marginal cost and rate design presentations) take the position that their showings are consistent with the policies we laid down in D.93887 and D.92479. The following is a discussion of their positions, as well as those of the other parties who took specific positions regarding marginal cost methodology as an element of rate design.

a. Edison

Although Edison had the benefit of D.92749 when it prepared the NOI and application in this proceeding, its application was filed before we issued D.93887. Edison asserts, nevertheless, that the marginal cost methodology it has relied upon is compatible with both of these policy decisions. In its opening brief, Edison offers the following rationale in support of this assertion:

> "It must be pointed out here that the Commission, in establishing the specific guidelines: 'Short-run energy plus short-run capacity costs should be used in setting rates,' in D.93887 did not put this concept in context with its earlier D.92749. The emphasis in the general conceptual approach adopted in D.92749 in calculating marginal

cost was in the 'identification of the least-cost-system response to a change in demand,' i.e., a utility's resource plan. Edison believes that D.93887, in recommending 'the short-run energy plus short-run capacity costs' for setting rates, did not foresake the emphasis of D.92749 on utility's resource plan. Edison's methodology is, therefore, consistent with both D.93887 and D.92749 on two counts as follows:

"(1) Edison's methodology is consistent with D.92749 because Edison's methodology is based on the utility's resource plan and is a forward looking methodology; and

"(2) Edison's methodology is consistent with D.93887 because Edison's methodology develops the short-run capacity costs based on the utility's existing system and planned resources."

Unlike Edison, the staff had D.93887 available when it prepared its presentation. The staff was thus able to conform its marginal cost methodology to its understanding of the policy we established in that decision. Edison, however, takes issue with the test year marginal cost methodology of the staff.

In so taking issue with the staff, Edison is in fact taking exception to the methodology we adopted in D.93887. Edison contends that:

a. A shortage cost method should not be used to estimate the marginal cost of capacity for retail-pricing purposes (rather, what

Edison characterizes as its more forward-looking analysis should be used); and

b. Transmission and distribution costs should be included in calculating the marginal cost of capacity for designing retail rates.

It is Edison's position that retail customers should receive forward-looking price signals so that many long-term investments in appliances, machinery, and building stock can be appropriately made. Edison reasons, therefore, that it is appropriate for marginal costs to provide retail customers with forward-looking price signals regarding the future resource costs of their electricity consumption reflected in the marginal capacity component of electricity prices. Edison contends that marginal energy costs for retail-pricing purposes should be based upon test year marginal costs which give appropriate price signals regarding the use of energy.

Edison does not believe a shortage-cost concept is appropriate for designing retail rates because of the difficulty in applying the theoretical concept to electricity prices. Edison states that, theoretically, the shortage cost (or rationing premium) is volatile by nature and fluctuates around the marginal cost of capacity depending upon the level of system reliability. Edison point out that this is a logical consequence since the shortage cost represents a rationing premium that must be added to the marginal energy cost to reduce the probability of a shortage, and, thus, probability of a shortage varies with different levels of system reliability.

As we stated in D.93887, this theoretical concept has so far been impractical to measure directly due to the lack of reliable data quantifying the benefits of avoiding a shortage and, therefore, in that decision we adopted a proxy for the shortage cost,

specifically, the annual capital cost of a CT. Edison's analysis of this proxy, however, is that, rather than representing the shortage-cost methodology for rate design, the proxy of a CT is appropriate only for a long-run methodology because the CT represents the least-cost response only in the long run. In its opening brief, Edison offers this analysis:

> "When the system is in equilibrium, the CT represents the least cost system response to add to system capacity and is therefore actually a long-run methodology. The shortage cost is supposed to represent action the utility could take in the test year to avoid a shortage. Possibly a CT could be added in the test year, but as D.93887 points out, it is a maximum calculation or upper bound of the shortage cost.
>
> "If the cost of a CT is used as a proxy, Staff witness Gardner recognized that system reliability (such as loss-of-load probabilities) in excess of planning targets during the test year should be considered to adjust the cost of a CT to more accurately reflect the rationing premium.[13] Using a CT as a proxy, without reflecting test-year system reliability, vastly overstates the test-year marginal cost of capacity and, in fact, represents a long-run approach. The foregoing represent the theoretical problems Edison submits exist if a CT is used as a proxy for the shortage cost.
>
> "For these reasons, Edison believes that its marginal cost exhibit, as set forth in Ex. 8, Part III,

---

[13] Edison states that it expects to have system loss-of-load probabilities below its planning targets during the test year and that, therefore, the shortage cost should be virtually zero.

provides the appropriate methodology for determining marginal costs for retail rate design.

"Additionally, since marginal transmission and distribution costs are legitimate costs incurred by the utility in providing service to its customers and the methodologies for calculating these marginal cost components were set forth in D.92749, Edison believes marginal costs for retail rates, in order to provide forward-looking price signals, should reflect marginal transmission and distribution costs. Ms. Gardner's methodology failed to include these costs without a proper basis."

Edison states that its Exhibit 8, supra, provides a marginal cost analysis which conforms to the following extract from the conceptual approach set forth in Appendix B to D.92749:

"9. The fundamental concept of marginal cost analysis is identification of <u>the least cost system</u> response to a change in demand. The source of this information is each utility's system planning department. The system planner will describe the changes which occur in the utility's resource plan if an increase or decrease in demand is explicitly recognized in the plan keeping system reliability constant.

"10. The system response identified by the planner provides the basic level of information to allow the calculation of marginal costs. The change in total cost caused by the change in demand can be calculated based on the affected units, time frames, and/or operating characteristics. While the

> marginal costs which result from alternate scenarios may not precisely reflect all of the system's planning options, they provide a usable estimate of the utility's marginal cost."

In conformance with the methodology adopted in D.92749, Edison states that it identified the least-cost system response to a change in demand to consist of specific units in its March 1981 generation resource plan (GRP) which would be affected by the smallest identifiable load reduction. The system response was described as a planning "scenario" made up of a combination of the cancellation of certain planned refurbishments over the 1986-1995 horizon and cancellation of a CT planned for 1996. The costs associated with the CT, including calculation of the fuel savings, are due to cancellation of the CT. In addition, Edison states that it calculated the marginal costs of energy, the marginal costs of transmission, marginal costs of distribution (including customer-related marginal costs and demand-related marginal costs), and considered this data in the development of its rate design proposals. Edison's marginal costs of energy and capacity are shown in Table XII-1.

b. Staff

As indicated above in the discussion of Edison's position, the staff showing conforms to the principles of the marginal cost policy we laid down for generic rate design purposes in D.93887. The details of the staff's marginal cost showing are described below.

TABLE XII-1

SOUTHERN CALIFORNIA EDISON COMPANY

SUMMARY OF MARGINAL COSTS

(1983 $)

Line No.	Item	Cost $/kWh Demand (1)	Energy (2)	Total (1)+(2) (3)
1.	Time-of-Use	0.0268	0.0854	0.1122
2.	Ag. & Pump.	0.0488	0.0893	0.1381
3.	LSP & LP*	0.0340	0.0902	0.1242
4.	Domestic	0.0465	0.0899	0.1364
5.	Street Light	0.0057	0.0879	0.0936

*Lighting-Small and Large Power.

(1) Energy Component of Marginal Cost

In its estimate of Edison's hourly marginal energy costs, the staff used a computer model in conjunction with the costing periods we adopted in D.92549 in Edison's 1981 rate case. The results are shown in Column A of Table XII-2, the remaining columns of which show marginal energy costs in 1983 dollars allocated to customer groups after allowance for line loss.

TABLE XII-2

STAFF MARGINAL COST OF ENERGY BY CUSTOMER GROUP

Test Year 1983

Time Period	Marginal Cost: Energy Before Losses ¢/kWh	Time-Of-Use		Agricultural and Pumping		Lighting-Small & Large Power		Domestic		Street Light	
		Line Loss Mult.	MC Energy ¢/kWh	Line Loss Mult.	MC Energy ¢/kWh	Line Loss Mult.	MC Energy ¢/kWh	Line Loss Mult.	MC Energy ¢/kWh	Line Loss Mult.	MC Energy ¢/kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
mer											
On Peak	7.573	1.059	8.020	1.112	8.421	1.117	8.459	1.117	8.459	1.117	8.459
Mid Peak	7.075	1.056	7.471	1.107	7.832	1.112	7.867	1.112	7.867	1.112	7.867
Off Peak	6.669	1.047	6.982	1.092	7.283	1.097	7.316	1.097	7.316	1.097	7.316
inter											
On Peak	6.965	1.053	7.334	1.102	7.675	1.107	7.710	1.107	7.710	1.107	7.710
Mid Peak	6.870	1.053	7.234	1.102	7.571	1.107	7.605	1.107	7.605	1.107	7.605
Off Peak	6.644	1.044	6.936	1.087	7.222	1.092	7.255	1.092	7.255	1.092	7.255
arly Average											
On Peak	7.321	1.056	7.731	1.107	8.104	1.112	8.141	1.112	8.141	1.112	8.141
Mid Peak	6.972	1.055	7.355	1.105	7.704	1.110	7.739	1.110	7.739	1.110	7.739
Off Peak	6.656	1.046	6.962	1.090	7.255	1.095	7.288	1.095	7.288	1.095	7.288

Using the computer model, the staff calculated the incremental operating costs of each generating unit in Edison's system at various levels of output and determined the probability of each being the marginal unit. Marginal energy costs were estimated by comparing this information with the expected demand at each hour of the year. Input data, such as hourly demands, heat rates, maintenance schedules, forced outage rates, capacity factors, and hourly load data were supplied to the staff by Edison. The staff assumed that low-sulfur oil would be the marginal fuel and adopted Edison's estimated test year price for that fuel of $7.49 per million British thermal unit (Btu). SONGS Units 2 and 3 and Palo Verde Unit No. 1 were not included in the test year marginal cost analysis because their effects are to be considered in separate offset rate proceedings. The staff's marginal energy costs are lower than those estimated by Edison in part because the incremental heat rates obtained from the staff's model were lower than those which Edison derived from its simulation model.

(2) Demand Component of Marginal Cost

The staff emphasized that there are a number of approaches to measuring the demand, or shortage, component of marginal cost. Each involves the cost of an option that the utility could exercise during the test year to preserve an acceptable level of reliability, such as purchasing electric energy or installing load management devices. There are also theoretical approaches to determining the shortage cost, among them, measuring the market clearing price and subtracting the marginal energy cost. The staff reports that it spent considerable time trying to perfect a practical application of this method but was unable to develop the required data to apply the concept. Therefore, the staff used the approach adopted in the test year 1981 PG&E rate case, i.e., it selected a CT because adequate data was available.

The staff estimated that the levelized cost of a CT installed in the test year would be $128 per kW per year. This figure was developed by estimating the capital cost of the turbine at 1983 price levels to be $455 per kW.[14] To this cost the staff applied a 28.27% annual carrying charge rate, which includes all the expenses of the CT, including return, taxes, depreciation, and O&M expenses but excluding fuel and other variable running costs to obtain a levelized annual cost of $128 per kW per year. The staff originally allocated this levelized annual cost evenly across all hours of the year, but later filed an exhibit at CMA's request which allocated this levelized annual cost by costing periods using capacity response ratios from Edison's Exhibit 8.

(3) Recommended Test Year Marginal Costs

Tables XII-3 and XII-4 summarize the staff estimate of test year marginal costs by combining the shortage cost (designated as "demand") and the energy cost by customer groups and time periods. The staff recommends that the numbers in Table XII-4 be used for rate design purposes, including the allocation of revenue requirement to customer groups. The staff believes that rates based on these marginal costs will provide consumers with good indicators of the current costs of their consumption.

---

[14] The source of the staff capital cost data for the CT was Edison's June 1980 CFM III filing with the California Energy Commission.

TABLE III-3

SUMMARY OF STAFF TEST YEAR MARGINAL COSTS BY CUSTOMER GROUP

Test Year 1983

ITEM	SUMMER ON	SUMMER MID	SUMMER OFF	WINTER ON	WINTER MID	WINTER OFF	YEARLY AVERAGE ON	YEARLY AVERAGE MID	YEARLY AVERAGE OFF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Time-of-Use									
Demand ($/kW/Mo)	20.93	.43	0	3.34	1.68	.20	12.14	1.05	.10
Energy (¢/kWh)	8.02	7.47	6.98	7.33	7.23	6.94	7.73	7.36	6.96
Agricultural & Pumping									
Demand ($/kW/Mo)	20.93	.43	0	3.34	1.68	.20	12.14	1.05	.10
Energy (¢/kWh)	8.42	7.83	7.28	7.68	7.57	7.22	8.10	7.70	7.26
Lighting-Large & Small Power									
Demand ($/kW/Mo)	20.93	.43	0	3.34	1.68	.20	12.14	1.05	.10
Energy (¢/kWh)	8.46	7.87	7.32	7.71	7.61	7.26	8.14	7.74	7.29
Domestic									
Demand ($/kW/Mo)	20.93	.43	0	3.34	1.68	.20	12.14	1.05	.10
Energy (¢/kWh)	8.46	7.87	7.32	7.71	7.61	7.26	8.14	7.74	7.29
Street Light									
Demand ($/kW/Mo)	20.93	.43	0	3.34	1.68	.20	12.14	1.05	.10
Energy (¢/kWh)	8.46	7.87	7.32	7.71	7.61	7.26	8.14	7.74	7.29

TABLE XII-4

SUMMARY OF STAFF TEST YEAR MARGINAL COSTS

Test Year 1983

Line No.	Item	Cost $/KWH Demand (1)	Energy (2)	Total (1) + (2) (3)
1	Time-of-Use	.0217	.0721	.0938
2	Agricultural and Pumping	.0246	.0756	.1002
3	Lighting-Large & Small Power	.0256	.0761	.1017
4	Domestic	.0233	.0758	.0991

c. TURN

TURN's position on the determination of marginal costs for rate design is consistent with the position it took in PG&E's 1983 test year rate case. TURN was an active participant in that proceeding as well as in this one. TURN is in agreement with much of the generic marginal cost policy that the Commission established in the PG&E case, and it supports the continued use of the D.93887 approach in this proceeding. In its opening brief TURN states that it "...fully supports this Commission's focus on short-run marginal costs for ratesetting purposes."

TURN agrees with the various criticisms that were raised on the record concerning the use of a proxy for the shortage cost. TURN suggests, as it did in the PG&E case, that the utility be ordered to undertake a study of direct estimation of shortage costs. In this connection TURN's witness laid out in his testimony a general methodology by which shortage costs could be estimated directly. The method, which would measure the market clearing price and subtract the marginal energy cost to obtain the shortage cost, would appear to be an improvement over the use of a proxy. However, as the staff stated in Exhibit 88:

> "While admittedly preferable, the market clearing price unfortunately remains a theoretical concept. The Economics staff spent considerable time trying to develop a practical application and determined that more information was needed about price elasticity (or the shape of the demand curve), the demand which would result from prices set at marginal energy costs alone, the level of system reliability which should be maintained and how the reliability should be measured. The PGandE decision also recognized the

> problems involved in directly calculating the shortage cost. The decision, therefore, adopted the capital costs of a gas turbine as a proxy because it represented a utility's least capital-intensive addition to capacity. We have also used the cost of a gas turbine to approximate the shortage cost absent better knowledge about the market clearing price. While there are a variety of proxies that could be used, this choice does not appear to be unreasonable in light of Edison's recent application for a gas turbine facility at Lucerne Valley."

d. CFBF

CFBF also urges the Commission to rely on the short-run marginal cost approach it used in D.93887. Consistent with that position, it supports the marginal cost methodology used by the staff, and it opposes use of the long-run marginal cost methodology used by Edison.

e. CRA

CRA advocates the use of long-run marginal costs as being consistent with the provisions of D.92749, supra. In Exhibit 95, CRA's witness gave the following opinion regarding why prices set to reflect only short-run costs may fail to send important signals to consumers:

> "The short run decisions of ratepayers relate to the intensity of use of an existing mix of appliances -- how many lights to burn, at what level to set the thermostat, whether to close off an unused room. The difficulty with short run consumption decisions is that they are more elastic during the off-peak periods than during the peak periods, particularly for

> temperature sensitive loads. To set the air conditioner's thermostat up, for example, saves energy during the relatively cool days of the summer, but on the hottest day of the year, any temperature setting, no matter how high, will still result in the air conditioner operating at full capacity."

CRA's witness relied upon the costs calculated by Edison with the exception of generation costs. To reflect the fact that the fuel savings from the marginal plant will more than offset the capital investment in that plant, he set generation costs equal to zero, in accordance with the staff's development of intermediate marginal costs in Exhibit 88.

f. FEA

FEA takes the position that Edison's long-run marginal costs should be used for revenue allocation and ratesetting. It asserts that marginal costs should be calculated in a manner cosistent with D.92749, which it contends specifically requires the inclusion of all capacity-related marginal costs, including generation, transmission, and distribution marginal costs. In Exhibit 93, FEA's rate design witness testified as follows:

> "Q: In this case the Commission's staff recommends the use of short-run marginal cost for rate design. Isn't this at variance with marginal cost pricing?
>
> "A: Yes it is. As I indicated previously, setting rates equal to short run marginal costs, which exclude transmission and distribution capacity costs, is consistent with the results which would obtain under competition. In a competitive environment if only short-run

marginal costs were covered by prices, capacity costs would not be covered, capacity would not be built, and the industry would disappear. This points out the absurdity of using short-run marginal costs which ignore capacity costs.

"Q: What are the consequences of using the staff's recommendations that rates be set equal to short-run marginal cost?

"A: In summary, the Staff's calculation of marginal cost amounts to taking account of marginal energy costs and long-run generation marginal costs, and ignoring transmission and distribution marginal costs. If prices were set equal to the Staff's version of marginal costs, electricity prices would be set below proper marginal cost, since about 30% of marginal capacity costs have been neglected. In essence, the Staff's use of its definition of short-run marginal costs, which excludes transmission and distribution marginal costs, gives customers the price signal that their consumption decisions do not affect SCE's transmission and distribution systems. This is tantamount to the assumption that the amount of SCE's investment in transmission and distribution facilities is completely independent of the load which is carried by these facilities. This assumption is simply wrong, and further points out the absurdity of using short-run marginal costs as a basis for pricing."

In its opening brief, FEA summarizes its position by urging the Commission to reject the staff's marginal costs for the following reasons:

> "(1) the concept of shortage costs is not easily calculated and cannot be done precisely;
>
> "(2) while theoretically agreeing that transmission and distribution shortage costs should be included, they have been excluded;
>
> "(3) these marginal costs contain a calculation error;[15]
>
> "(4) the results of the methodology are non-sensical; and
>
> "(5) more straightforward calculation, that is, using LRMC, should theoretically produce the same results as the Staff's SRMC."

---

[15] FEA's witness asserted that the staff errs in the computation of shortage cost, among other reasons, because it divides the annual cost of capacity by the number of hours in the year. CMA and CRA also took exception to this staff assumption that Edison's capacity costs are constant for all hours of the year. Later staff exhibits allocate capacity cost by costing periods, as discussed previously.

g. CMA

CMA points out that the staff's marginal costing methodology is based on only two elements, the energy cost element plus the shortage cost element and that, therefore, the two cost elements must be based on accurate data and be clearly defined if the price signal they produce is to be accurate.

As to the energy cost element, CMA contends the staff has calculated the marginal energy cost incorrectly because the fuel costs used in the calculation are not those which will prevail in the test year. CMA brings out that the staff's marginal cost witness admitted under cross-examination that her marginal energy cost figures, which were based on a price of $8.50 per million Btu, should be revised downward to reflect lower oil costs. The staff's rate design witness, however, maintained that the original estimate should be retained.[16]

In it opening brief CMA makes the following criticism of the staff's determination of the energy element:

> "The very heavy reliance on fuel cost estimates creates a serious problem. Energy prices under current market conditions are too unstable to support a reasonable expectation that cost estimates made months before the start of the test year will reflect test year costs. The available evidence shows that fuel costs have changed even since

[16] Originally, the staff adopted Edison's test year price of $8.50 per million Btu as the price of the marginal fuel (low-sulfur fuel oil). Edison subsequently made a substantial downward reduction in its estimated test year price of fuel oil. The staff figures used in this decision reflect this downward revision, as do the adopted cost allocation and rate design.

> Edison's revised estimate was made and that these costs will continue to change well into 1983. Thus, because they are based on the fuel cost estimates which already have been rejected as incorrect, the Staff rates are certain to send false price signals to consumers in the Test Year and create economic inefficiency."

With respect to the shortage element, CMA objects to the staff's marginal cost determination on the following grounds:

> (1) The shortage cost concept represents pricing in a monopoly market, not a competitive market, and thus its application violates basic regulatory principle.
>
> (2) Edison's resources are such that it cannot be considered to have a potential for capacity shortage; therefore, its ratepayers must not be charged a premium based on the hypothecation of such a shortage.
>
> (3) Rates based on a nebulous proxy concept cannot send as accurate a price signal to ratepayers as rates based on real, calculable costs of service. Rather, a meticulous calculation must be made of the marginal costs of all aspects of electric service performed by Edison.

3. Adopted Test Year Marginal Costs

In D.92749 we defined marginal costs as being "the change in total costs which results from a change in output." The change in total costs, however, varies depending on whether one is talking about the short run, when capital investments are fixed, or the long run, when the costs incurred to meet output changes can include new investments. Whether a short- or long-run marginal cost analysis is appropriate depends on the pricing problem at hand.

For retail electricity rates, we concluded in D.93887 that a short-run marginal cost methodology is more appropriate. During the test year utility plant is largely fixed. Short-run marginal cost-based retail prices signal to consumers the marginal energy and shortage costs caused by additional kWh's of demand on their part during the test year. Customers can thus respond to signals about the current reserve margin situation on the utility system (marginal shortage costs) and current fuel prices (marginal energy costs). This is desirable because customers can respond relatively quickly to changing system costs and conditions, more quickly in general than can utility supply. For example, if reserves are temporarily too low and shortage costs are high, customers being signaled high shortage costs can shift demand to off-peak periods more quickly than the utility can build new "peaker" powerplants, and this customer responsiveness can return reserve margins more quickly to target levels. Short-run marginal cost-based retail rates rely on customer responsiveness and the need to signal customers about current system conditions. As we stated in D.93887, "we want to show the customer the present cost of his consumption."

Edison has argued in this proceeding that customers also make many longer-lived investment decisions, such as installing insulation in their homes, and that they should therefore receive marginal cost signals that reflect the longer-term marginal cost situation on the utility system. Thus, if reserve margins are now very low but are expected to be very high five years from now after new utility plant, now under construction, comes in line, Edison would argue that we should send price signals that reflect the longer-term high reserve margin situation, not the current low reserve margin situation.[17]

---

[17] Strictly speaking, short- and long-run marginal costs are differentiated not by time frames but by whether more or less inputs such as capital can be varied. However, it is useful in examples such as this to use the longer-term time frame to show the effects of varying capital inputs.

There is some merit in Edison's argument. However, the marginal cost method it would have us adopt pursuant to this argument is inadequate. Edison's marginal cost method for defining retail rates is based on long- (or "intermediate") run shortage or capacity costs and current or short-run energy costs. This is an inappropriate mixture of short- and long-run concepts. Clearly "intermediate" or long-run adjustments in capital will affect marginal energy costs. Simply adding current energy costs to long-run capacity costs will lead to total marginal costs that do not correctly signal either the current or the longer-run state of the utility system.

We will adopt the staff short-run marginal cost method for defining retail rates. This method relies more on the value of customer responsiveness to current system conditions and is generally consistent with D.93887.

As a part of adopting the staff method, we adopt the capital cost of a combustion turbine as a proxy for test year shortage costs. The use of the full capital cost of the combustion turbine is only appropriate as a proxy for shortage costs if reserve margins on the utility system are close to target levels. The conceptual basis for this view is that when a utility system is in equilibrium, with reserve margins equal to target levels, the customer cost of not meeting an additional increment of peak demand (the shortage cost) is equivalent to the utility cost of supplying the demand in a least cost way (building more peaking capacity such as a combustion turbine).

We agree with Edison that if reserve margins are higher than target levels, the shortage cost will be less than the full cost of a combustion turbine. However, Edison's downward adjustment in the combustion turbine proxy in Exhibit 137 will not be used here because it was shown by staff to be based on unrealistic assumptions about SONGS Units 2 and 3 and Palo Verde Unit 1 being on line (Tr. 6241-45). Removal of these plants from the projected system mix

brings reserve margins down to the range of target levels.[18] Therefore, the full cost of a combustion turbine is an adequate proxy for current Edison shortage costs.

We will make one revision in the staff's shortage cost method. The capital cost of the combustion turbine will be calculated using a real economic carrying charge rather than a levelization factor. This is consistent with our decision in D.93887 and better reflects the concept of short-run marginal costs. The effect of this change is to reduce staff's 1983 combustion turbine cost of $128/kW/yr. The adopted test year shortage cost to be used for rate design, $58/kW/yr, is derived from the Edison single-year gas turbine cost in Exhibit 137 adjsuted for inflation. We will address the issue of shortage costs further in our decision in A.82-03-037, the Edison OIR 2 compliance proceeding.

We also are persuaded by the arguments of FEA in this proceeding and agreed to by TURN and staff, that short-run marginal costs that are used as a basis for retail rates should include a transmission and distribution shortage cost component. The transmission and distribution shortage cost component is based on the same rationale as the generation shortage cost, which we have proxied using a combustion turbine. As in the case of generation, transmission and distribution lines also have capacity limits that are sometimes approached during the operation of the system. During these peak periods, the probability of a shortage will increase. If demand increases, current and projected transmission or distribution shortage costs will also increase. If demand increases sufficiently, these current and projected shortage costs will, on a present value basis, exceed the cost of building new transmission and distribution lines and such lines will therefore be worth building.

We believe that transmission and distribution shortage costs should be a part of current or short-run system marginal costs. However, we agree with TURN that the record in this

---

18 Based on Exhibit 8.

proceeding is insufficient to establish transmission and distribution shortage costs at this time. For example, since many distribution elements are oversized, marginal distribution costs derived from a simple linear regression such as Edison's probably overstate distribution shortage costs. In future rate cases we would hope to see efforts to accurately estimate transmission and distribution shortage costs.

We agree with FEA, CMA, and CRA that Edison's capacity costs should be allocated by costing periods, and will rely on the capacity response ratios in Edison's Exhibit 8.

The adopted test year marginal costs are given on Table XII-5. These shall be used for revenue allocation and rate design.

3. Incremental Heat Rates

Both Edison and the staff offered incremental heat rates for purposes of computing marginal costs and payments to Qualifying Facilities. Consistent with our adoption of the staff's marginal costs, we have adopted staff's incremental heat rates. These adopted heat rates are shown on Table XII-5A.

TABLE XII-5

SUMMARY OF
ADOPTED TEST YEAR MARGINAL COSTS

Test Year 1983

:Line: :No. :	Item	Cost $/kWH Demand (1)	Energy (2)	Total (1) + (2) (3)
1	Time-of-Use	.0101	.072080	.082180
2	Agricultural and Pumping	.0115	.075605	.087105
3	Lighting-Large & Small Power	.0120	.076134	.088134
4	Domestic	.0109	.075781	.086681

TABLE XII-5A

ADOPTED INCREMENTAL HEAT RATES

Test Year 1983

Costing Period	(Btu/kWh)
Summer:	
On Peak	10,087
Mid Peak	9,422
Off Peak	8,879
Winter:	
On Peak	9,275
Mid Peak	9,148
Off Peak	8,847

B. Allocation of Revenue Requirement

1. General

After the California jurisdictional costs have been determined, the cost-of-service analysis develops the retail revenue requirement necessary to recover costs at the requested rate of return. This determination is necessary because revenue requirement in this jurisdiction is based on historical cost. Depending on circumstances, the direct application of marginal cost-based rates to customers' billing determinants will produce either more or less revenue than the revenue requirement based on average costs; therefore, for purposes of rate design, marginal costs must be adjusted downward or upward.

The method by which the revenue requirement should be allocated to customer groups constitutes one of the more intensely contested issues of this proceeding. As discussed below, several methods were offered by the parties.

2. Position of the Parties on Allocation

a. Edison

Marginal costs as computed by Edison are substantially higher than the revenue requirement. It was Edison's original position that cost recovery by customer group should be accomplished by increasing the revenue responsibility of each group by an equal percentage of the total increase (EPI) as shown in Table XII-6. Edison states that the EPI method was chosen after careful consideration of general ratemaking principles together with the language and findings in D.92549, as amended, wherein we found that "Adjusting marginal costs to a utility's revenue need involves the application of judgment and experience rather than simply a statistical formula." Edison further states that it did not use the marginal cost procedures previously adopted by this Commission because of the resulting disparity in the treatment of the different customers groups.

TABLE XII-6

EDISON'S PROPOSED ALLOCATION OF COST
RECOVERY TO CUSTOMER GROUPS - EQUAL PERCENTAGE OF INCREASE METHOD

Test Year 1983

Customer Group	Proposed Rates	Present Rates	Increase	
	(In Millions of Dollars)			%
Domestic	1,636.1	1,383.5	252.6	18.3
Lighting - Small and Large Power	1,694.8	1,433.2	261.6	18.3
Time-of-Use	1,734.5	1,466.7	267.8	18.3
Agricultural and Pumping	118.6	159.5	29.1	18.3
Street and Area Lighting	81.9	69.3	12.6	18.3
Subtotal	5,335.9	4,512.2	823.7	18.3
Santa Catalina	1.9	1.6	.3	18.3
Total	5,337.8	4,513.8	824.0	18.3

b. Staff

The staff allocated the revenue requirement to customer groups using adjusted short-run marginal costs and the equal percentage of the difference (EPD) method. The staff allocation procedure is explained in Exhibit 88 at page 2-5, as follows:

> ". . . Depending on the final revenue requirement authorized in the Commission decision, these SRMC costs can be adjusted up or down using either the equal percent of the difference method (EPD) or the equal percent of marginal cost method. The difference between the methods is shown in Table 3. The staff has been proposing the EPD method in prior cases because it caused the least dislocation between present and proposed rates. After several iterations of the EPD method over a period of years, and as all group rates are now closer to SRMC costs, either method can now be used."

Table XII-7 shows a comparison of revenues at Edison's proposed rate level allocated according to the staff-recommended method, which Edison now accepts. Table XII-8 shows the method by which the staff made the allocations shown in Table XII-7.

TABLE XII-7

SUMMARY OF STAFF PROPOSED REVENUE ALLOCATION
BY CUSTOMER GROUP
Test Year 1983

	A	B	C	D	E	F	G
		In Thousands of Dollars			In Cents per KWh		
Customer Group	Sales GWH	Proposed Base Revenue	Offsets 1/ ECAC, AER, CEMA	Proposed Effective Revenue (B+C)	Proposed Avg. Base Revenue	Offsets 1/ ECAC, AER, CEMA	Proposed Avg. Effect. Revenue
Domestic	16,588.8	772,833	617,517.2	1,390,350	4.659	3.723	8.381
Lifeline	9,040.9	421,194	225,932.1	647,126	4.659	2.499	7.158
Non-lifeline	7,547.9	351,639	391,585.1	743,224	4.659	5.188	9.847
Light & Power	16,232.1	758,014	734,177.9	1,492,192	4.670	4.523	9.193
Time-Of-Use	19,061.8	712,325	862,165.2	1,574,490	3.737	4.523	8.260
Agriculture	1,809.6	82,199	81,848.2	164,047	4.542	4.523	9.065
Sub-Total	53,692.3	2,325,371	2,295,708.5	4,621,080	4.331	4.276	8.607
Street & Area Light	498.7	54,096	22,556.2	76,652	10.847	4.523	15.370
Total	54,191.0	2,379,467	2,318,264.7	4,697,732	4.391	4.278	8.669
Pub. Auth. & Fringe	528.5	2,224		2,224			
TOTAL CPUC	54,719.5	2,381,691	2,318,264.7	4,699,956	4.353	4.237	8.589

1/ Offsets in effect as of 9/82.

TABLE XII-8

STAFF SRMC REVENUE ALLOCATIONS
BY CUSTOMER GROUPS
Test Year 1983

(In 000's)

Customer Group 5/	A Sales GWH	B Current Base Revenue	C Offset ¢/kWh ECAC: AER CLMA 2/ (eff.9/82)	D Offset Revenue (A*C)	E Total Current Revenue (B+D)	F Total Base Proposed 1/ Increase (EPD*K-B) 3/	G Total Proposed Revenue (E+F)	H SRMC ¢/kWh	I Total SRMC (A*H)	J Average 4/ Fuel Cost (A*4.276)	K Base SRMC (I-J)	L Total Base % Incr. (F/B)
-estic	16,588.8	570,749	3.723	617,517.2	1,188,266	202,084	1,390,350	9.910	1,643,950	709,337	934,613	35.4
Lifeline	9,040.9	311,058	2.499	225,932.1	536,990	110,136	647,126	9.910	095,953	386,589	509,364	35.4
-on-lifeline	7,547.9	259,691	5.188	391,585.1	651,276	91,948	743,224	9.910	747,997	322,748	425,249	35.4
-ight & Power	16,232.1	509,805	4.523	734,177.9	1,243,983	248,209	1,492,192	10.170	1,650,805	694,085	956,720	48.7
-e-Of-Use	19,061.8	386,817	4.523	862,165.2	1,248,982	325,508	1,574,490	9.380	1,787,997	815,083	972,914	84.2
-riculture	1,809.6	55,036	4.523	81,848.2	136,884	27,163	164,047	10.020	181,322	77,378	103,944	49.4
Sub-Total	53,692.3	1,522,407.0	4.276	2,295,708.5	3,818,116	802,964	4,621,080	9.792	5,264,074	2,295,883	2,968,191	52.7
-reet & Area Light	498.7	40,793	4.523	22,556.2	63,349	13,303	76,652					32.6
Total	54,191.0	1,563,200.0	4.278	2,318,264.7	3,881,465	816,267	4,697,732					52.2
-b. Auth. & Fringe	528.5	2,224	0	.0	2,224		2,224					.0
-OTAL CPUC 6/	54,719.5	1,565,424.0	4.237	2,318,264.7	3,883,689	816,267	4,699,956					52.1

1/ Base increases are assigned using the EPD method, excepting Street & Area Lighting, which is based on average total increase.
2/ ECAC rates current as of 9/82: AER=.236, CLMA=.001.
3/ EPD factor is based on $\frac{\text{Prop. Base Increase (4 Cust. Groups)}}{\text{Base SRMC - Current Base Subtotal}} = \frac{802,964}{1,445,784} = .5553831$
4/ Average Fuel Cost used in marginal cost calculations is the average offset cost for those groups.
5/ Catalina has been spread into the sales and base revenue numbers. Public Auth. & Fringe revenues are contractual.
6/ Columns may not add due to rounding.

c. TURN

TURN's witness proposed another type of revenue allocation, which he referred to as the "class marginal rate - class marginal cost" (CMR-CMC) methodology. This method of allocation differs from the EPD and equal percentage of marginal cost (EPMC) with respect to one basic premise: EPD and EPMC equate total class[19] revenues and, therefore, average rates per kWh, with class marginal rates; CMR-CMC method, on the other hand, seeks to establish marginal rates for the various classes at a uniform percentage of their respective marginal cost. TURN's witness states that his CMR-CMC methodology takes rate structure (prices) into account, while EPD and EPMC do not. TURN's opening brief characterizes the CMR-CMC concept as "really quite simple" and describes it as follows:

> "Basically it sets the marginal rate for each customer class at an equal percentage of class marginal cost. The closer that percentage is to 100% of marginal cost, the more accurate the price signal to customers. The goal is to achieve as close an approximation as possible of the economically efficient pricing that would occur in a free, competitive market.
>
> "The marginal rate is the rate that customers face when they increase or decrease consumption by small amounts. Thus, the marginal rate determines what additional resources (dollars) the customer must surrender when usage is increased. Likewise, it is the marginal rate that establishes the monetary reward or incentive for conservation. If the marginal rate is equal to marginal cost, the customer pays or saves an equal to the full resource cost of his/her changes in consumption of

---

[19] The term customer class (or class) and customer group (or group) are used interchangeably in this discussion.

> electricity. Economic efficiency is realized and wasteful use of scarce resources is discouraged. Even if the customer is not aware of the rate structure itself, the effect of the marginal rate shows up in the monthly bill as a result of increases or decreases in usage."

TURN's allocation method would be applied to develop total effective rates in each Edison rate proceeding, and would specifically include Edison's ECAC rate revisions.

TURN did not find much support for the CMR-CMC methodology among the other parties to the proceeding. Edison commented on the CMR-CMC methodology in its opening brief:

> "Without addressing the details of this methodology in this opening brief, the residential revenue allocation produced by the CMR-CMC method is strongly influenced by the degree of inversion in the residential rate and the number of tiers. Dr. Wells' own calculations demonstrate that he would allocate nearly $100 million more to the residential class under his methodology with a two-tier residential rate structure and a 35% differential in tiers.
>
> "This is true even though the class marginal rate is less than the class marginal rate of his own proposal. This and another example set forth in Mr. Ferguson's rebuttal to Dr. Well's methodology demostrate that the allocation under this methodology is influenced much more strongly by the degree of inversion and/or the number of tiers than by the class marginal rate. Additionally, no customer ever sees the class marginal rate.
>
> "It seems hard to conclude anything other than that the class marginal rate of Dr. Wells' methodologies reflects the specific number that

results under any particular tier structure or degree of inversion. It is thus an arbitrarily determined number and has no relationship to marginal costs. Where can there be any conservation value (or any other value) to a revenue allocation method that can change the revenue allocation by $100 million or more for a particular class based upon nothing more than the degree of rate inversion or number of tiers adopted?"

TURN asserts that the Commission should consider external or social costs as an element in revenue allocation and rate design; however, in its opening brief, it qualifies its enthusiasm for externalities with this statement: "TURN certainly does not favor inclusion of such costs in Edison's revenue requirement, nor the reflection of them in higher payments to qualifying facilities."

TURN also suggests that it may be desirable to adopt at least tentatively an estimated value for social costs. However, the record fails to provide any reasonable basis for considering external costs in revenue allocation and rate design or for adopting a value for such costs, tentative, or otherwise.

d. CFBF

CFBF suggests that Edison's EPI revenue requirement allocation proposal is inconsistent with this Commission's policy on marginal costs. CFBF takes the position that, if the Commission desires mere compatibility with marginal costs, then the Edison proposal has considerable merit; if, however, marginal costs are to be the actual basis for rate spread, then the staff propsoal should be accepted.

CFBF, in it opening brief, characterizes TURN's CMR-CMC method of revenue allocation thus:

"TURN, through its witness Dr. Fred Wells, advocates a drastic departure from traditional marginal cost

concepts as applied to revenue allocation. It is conceptually unsound, it contradicts basic rate design principles and it imposes inequitable and severe economic consequences upon all non-residential customers. It should be rejected."

e. CRA

While CRA supports the use of LRMC in developing the revenue spread, it urges the Commission to reject the EPI method by which Edison allocated the LRMC to customer groups. CRA points out that the revenues currently generated from each customer class are severely out of balance with the distribution of marginal costs. CRA's witness calculated that the domestic class generates revenues equivalent to only 47% of its marginal costs as quantified by Edison, while the two general service categories generate revenue amounting to 74% of their marginal costs.

CRA takes the position that the CMR-CMC method sponsored by TURN fails to allocate revenues in a reasonable and efficient manner. According to CRA, the flaw in this method is that it abandons entirely any attempt to allocate revenue to the classes in proportion to the costs of serving the respective classes. CRA argues tht TURN's CMR-CMC proposal does not allocate revenues according to cost, which this Commission has traditionally used for allocating revenues. CRA states that, instead, TURN's revenue spread is a function of rate design, not of cost, because revenue is allocated relative to the relationship which CMR bears to the CMC, and because the CMR is itself the product of rate design. CRA asserts that the CMR is an illusory and fallacious notion; that it is not a "rate" at all; and that no customer pays the CMR.

f. FEA

FEA provided the following comments on the CMR-CMC method in this opening brief:

"Dr. Wells has proposed a novel revenue allocation scheme. Dr. Wells

has advocated using marginal costs to allocate the revenue requirement. His method differs from the usual allocation methodology by using what he terms as class marginal revenue in place of the class revenue requirement. Dr. Wells considers the class marginal revenue as each customer's marginal energy charge times his total consumption. Thus, with inverted rates the total consumption of a customer would be valued at the tailblock and the lower initial blocks of energy ignored. Dr. Wells has adopted the class marginal costs developed by the Staff in Exhibit 88, page 2-10, and an equal percentage of the class marginal costs was used to reconcile the class marginal revenues with the marginal costs.

"Dr. Wells' methodology should be rejected for the following reasons. (1) it is theoretically wrong in not producing results consistent with competitive pricing; (2) his method is subject to manipulations since the results change with each change in rate design; and , (3) his revenue allocation, as discussed supra, at pp. 21-26 is based on a flawed marginal cost study.

"The essential flaw in Dr. Wells' proposed class revenue requirement determination process is that there is no market mechanism by which his results would be brought about in the competitive marketplace, and thus his result must be at variance with the results of such a competitive marketplace. In a competitive marketplace, prices are forced equal to LRMC because any price above or below marginal cost would automatically produce above or below normal profits which would be eliminated by the competitive entry

> or exit of additional capacity. This is the 'invisible hand' or self correcting nature of a competitive market. Since Dr. Wells' Class Marginal Rate-Class Marginal Cost (CMR-CMC) methodology is a totally artificial and arbitrary process, there is simply no way by which it could emerge in a competitive pricing process, and thus there is no way by which the market process could work to produce the results recommended by Dr. Wells.
>
> "On a practical level Dr. Wells methodology provides little guidance in making revenue allocation between classes. The class marginal revenue which is central to his method is dependent on the rate design assumed for each class. By altering the rate design the class marginal revenues will change. This, in turn, will change the amount of the increase allocated to the class. Thus, the revenue allocation among the classes flows from the rate design assumed for each class of customers. (Tr. 6406-6407.) This method lends itself to self serving manipulation rather than practical guidance, since the amount of revenue allocated to a class of customers can be reduced by changing the rate design.
>
> "Dr. Wells relies upon the Staff's SRMC for his revenue allocation. As discussed supra, at pp. 21-26, the Staff's SMRC is seriously flawed and should not be used for revenue allocation or rate design. Dr. Wells' allocation is consequently tainted by using the flawed marginal costs."

FEA believes that Edison's LRMC should be used for revenue allocation purposes in a manner which is neutral to income distribution. It favors the EPMC methodology for reconciling LRMC

with the constraints of revenue requirement. Because strict application of the EPMC method would produce large increases for some customer classes, FEA, in its Exhibit 93, recommends a modified EPD method which would ease the transition to marginal cost pricing by limiting the increase to any customer class to 1.25 times the system average increase. FEA supports the concept of allocating revenues based on a total revenue requirement to determine a total effective rate.

g. CMA

CMA argues that Edison's EPI method of rate increase allocation distributes the base revenue requirement inequitably among customer groups, ignores Edison's own cost figures, and perpetuates the inaccurate price signals given by present rates. CMA accuses Edison of choosing a revenue allocation method which serves to insulate the domestic customer group from both its marginal cost and embedded cost responsibility. Since domestic customers pay a relatively smaller portion of their total revenue requirement through offset rates than do other customers, CMA brings out that the EPI method produces a much smaller proportionate increase in base rates for them than for other customer groups.

CMA asserts that the revenue allocation the staff has devised for this proceeding is based on inaccurate estimates of energy costs, the false shortage concept, and an unjustified EPD methodology. CMA contends that the EPD method, like Edison's EPI method, perpetuates the misallocation of revenue requirement reflected in present rates.

In order to make its marginal cost calculation fit the revenue requirement, the staff allocated the additional dollar amount required to meet the revenue target by multiplying each customer group's estimated marginal cost by the percentage difference between the total calculated marginal cost and the total revenue requirement. CMA argues that, through the use of this mechanical

formula, the existing difference between present rate allocations and calculated costs is carried through; and that, as a result, CMA contends that the price signals created from an equal percentage of the difference adjustment are less accurate than those which would be derived under a strictly cost-based adjustment.

As CMA sees it, TURN's CMR-CMC proposal is simply a scheme to shift revenue requirement responsibility from residential to nonresidential users. In its opening brief CMA offers these comments:

> ". . . The proposal introduces the concept of a Class Marginal Rate ('CMR') which for all classes but residential is simply the <u>average rate</u> in cents per Kwh paid by such customers. Customer, demand and energy charge revenues are all lumped together and divided by sales to provide a CMR expressed in cents per Kwh. For the residential class, however, the CMR is a bit more complex. Dr. Wells developed an algebraic formula that weights the tier rate faced by customers whose bills end in each of the three rate tiers by the percentage of total residential sales represented by the bills ending in each rate tier.

> "The TURN proposal is obviously very attractive to residential customers as it would result in such customers paying increased revenues of $147 million during the test year instead of the $990 million increase which would be required if the revenue requirement sought by the company were spread on the basis of each class paying an equal percentage of full marginal cost. Dr. Wells' approach would shift nearly $850 million in annual revenue requirement from residential customers to non-residential, principally TOU, customers."

CMA asserts that the record of this case demonstrates, again, the many shortcomings of marginal cost ratemaking. CMA ranks the major shortcomings as follows:

1. The lack of a coherent, universally accepted definition of marginal cost: Edison produced one set of numbers based on one definition; the staff produced several sets of numbers based on a variety of definitions; and TURN produced yet another set of numbers. CMA suggests that none of these methods has produced an accurate measure of the costs of Edison's electric service for the test year 1983.

2. The manipulability of the marginal cost concept for the purpose of achieving desired revenue requirement allocations. This difficulty, CMA states, stems from the first problem: absent a clear definition of what costs are to be assigned to electricity use, a party may choose whatever costing scheme fits its desired revenue allocation result. From CMA's viewpoint, it appears hardly coincidental that the staff and TURN rate design witnesses adopted marginal costing methods which would result in a lower revenue requirement to the domestic customer group than that proposed by Edison or that which would be indicated under an embedded cost approach. CMA suggests that until firm guidelines are established for the assignment of costs to customer groups, the goal of sending accurate price signals through rates will not be achieved.

3. The necessity for the adjustment of marginal cost based revenue responsibility estimates to the utility's revenue requirement,

> which is based on Edison's fully allocated cost of service, not on marginal cost theory. Thus, CMA brings out, based on the same data, that the staff arrived at a total marginal cost estimate substantially lower than the revenue requirement, whereas Edison arrived at a total marginal cost estimate substantially higher than that same revenue requirement.

As a basis for rate design, CMA urges the Commission to consider costing techniques such as the monthly peak responsibility method. CMA points out that this allocated cost of service method is used to determine FERC and CPUC jurisdictional costs and rates of return as well as the incremental revenue requirement necessary to raise CPUC rate levels to cover costs at the required rate of return. CMA suggests that because this type of allocation is useful for these purposes, it should also be useful for the allocation of the revenue requirement to customer classes.

h. CIEC

CIEC in its opening brief takes the following position regarding Edison's and the staff's proposed revenue requirement allocations:

> "The purported even-handedness of Edison's proposed uniform increase is illusory. As noted by several witnesess, Edison's proposed revenue allocation, when evaluated in reference to the base rate revenues which are the only revenues at issue in this general rate proceeding, produces widely disparate increases and corresponding returns on common equity. Thus, as pointed out by CIEC witness Chalfant, Edison's proposal, when compared to present base rates, results in a percentage increase to the time-of-use class which is approximately 1.35 times the average for the five major customer groups and more than 1.6 times the

> percentage increase proposed for the domestic class.
>
> "The disparities in the increases proposed for various customer classes are even more aggravated in the case of Staff's proposed revenue allocation. Again, employing present base rates as the appropriate point of reference, it may be seen that Staff's proposal would result in a percentage increase to the time of use class which is approximately 1.7 times the average for the five major customer groups and nearly 2.5 times the percentage increase proposed by Staff for the domestic class. Indeed, Staff's proposal is skewed to the extent it produces substantially disparate increases to Edison's customer classes even in relation to <u>total effective rates</u>."

CIEC proposes that any additional electric revenues authorized be allocated by way of a system average percentage increase on present base rates. CIEC considers that such a distribution would certainly not represent a movement in the direction of insuring that every aspect of cost incurred by Edison is matched by a corresponding revenue recovery. CIEC contends that it would, however, stop the movement away from cost-based rates; that it might prevent serious harm to the California economy, including the loss of many jobs; and that it would also insure that all customer classes would be recovering, at the very least, Edison's senior capital requirements.

3. <u>Adopted Method of Allocation</u>

Our adopted method of allocation of the revenue requirement among customer groups is based on the use of short-run marginal cost as determined in the manner described above.

Both TURN and FEA proposed that the adopted revenue allocation method be used to allocate both base and offset revenues to determine a total effective rate. Unfortunately, the record in

this proceeding is insufficiently developed to adopt this proposal, although we believe that it has merit. Since we are using short-run marginal cost in allocating the revenue requirement, it appears appropriate to include the marginal energy cost as a necessary component of total marginal cost. Also, the application of marginal cost to the total revenue requirement would reduce to a larger extent the difference between class marginal costs and adopted rates. However, for the reason already indicated, we decline to allocate revenues using a total revenue requirement, and will continue to allocate base revenue and offset revenue separately. We instruct Edison and our staff to develop a proposal to allocate revenues based on a total revenue requirement for consideration in Edison's next general rate case.

We turn now to the revenue allocation method. Concurrently with our review of the allocation of revenue requirement in this proceeding, we have reviewed this issue in the rehearing of D.93887 for PG&E. In both proceedings many of the same parties participated and offered essentially the same differences of position.

We believe that parties have raised a number of valid criticisms of TURN's proposed revenue allocation method. As pointed out, the CMR for the residential class is determined by the slope of the rate inversion between the residential tiers. Any alteration of the degree of inversion between the two tiers will change the residential CMR which in turn modifies the revenue allocation to the residential class. We therefore agree with the criticism that the CMR can be manipulated by the degree of inversion between the residential tiers which we adopt.

Another problem with TURN's method is that mechanically it is very difficult to apply. Moreover, since the residential rate design determines the CMR, it is necessary to establish the residential rate design before applying the revenue allocation method.

Lastly, under the TURN method the lifeline subsidy is borne by all customer classes, not just the residential class. This is a major departure from our practice in the last several general rate decisions of setting the average residential rates at approximately the system average rate. This practice allows the residential class to support entirely the lifeline discount which this class enjoys. We believe that it is appropriate to continue this practice for designing residential rates.

For all of these reasons we decline to adopt the revenue allocation method proposed by TURN. We also are not persuaded that the methods proposed by Edison and other parties offer a substantial improvement over our existing allocation method. After careful consideration, we will continue the EPD revenue allocation adopted in D.93887.

In Table XII-9, details of the adopted EPD revenue allocation are shown. This information is summarized in Table XII-10. As discussed in Section XII.C, we set the residential lifeline total rate at 80% of the system average total rate. In a companion decision issued today, we are adopting a $286.8 million rate reduction for Edison under the ECAC procedures. This reduction offsets the increases of $580.9 million authorized in this decision. The total effect on rates of these two decisions, by customer group, is shown in Table XII-11.

TED REVENUE ALLOCATIONS BY MAJOR CLASSES
Test Year 1983

(In 000's)

Customer Group 5/	A Sales GWH	B Current Base Revenue	C Offset ¢/kWh ECAC: AER CLMA 2/ (eff. 1/83)	D Offset Revenue (A*C)	E Total Current Revenue (B+D)	F Total Base Proposed 1/ Increase (EPD*K-B) 3/	G Total Proposed Revenue (E+F)	H SRMC ¢/kWh	I Total SRMC (A*H)	J Average 4/ Fuel Cost (A*3.778)	K Base SRMC (I-J)	L Total Base % Incr. (F/B)
stic	16,588.8	570,749.3	3.201	531,053.1	1,101,802	128,613	1,230,415	8.668	1,437,917	626,725	811,192	22.5
Lifeline	9,169.5	315,624.4	1.881	172,478.3	488,103	71,015	559,118	8.668	794,812	346,424	448,388	22.5
Non-lifeline	7,419.3	255,124.9	4.833	[illegible],574.8	613,700	57,597	671,297	8.668	643,105	280,301	362,804	22.6
ght & Power	16,232.1	509,804.5	4.036	655,127.6	1,164,932	164,472	1,329,404	8.813	1,430,535	613,249	817,286	32.3
-Of-Use	19,061.8	386,816.7	4.036	769,334.2	1,156,151	245,801	1,401,952	8.218	1,566,499	720,155	846,344	63.5
riculture	1,809.6	55,036.3	4.036	73,035.5	128,072	18,310	146,382	8.711	157,634	68,367	89,267	33.3
Sub-Total	53,692.3	1,522,406.8	3.778	2,028,350.4	3,550,957	557,195	4,108,152		4,592,585	2,028,496	2,564,089	36.6
reet & Area Light	498.7	40,792.9	4.036	20,127.5	60,920	9,564	70,484					23.4
Total	54,191.0	1,563,199.7	3.780	2,048,677.9	3,611,878	566,758	4,178,636					36.3
Pub. Auth. & Fringe	528.5	2,224.4			2,224		2,224					
TOTAL CPUC 6/	54,719.5	1,565,424.1	3.744	2,048,677.9	3,614,102	566,758	4,180,860					36.2

/ Base increases are assigned using the EPD method, excepting Street & Area Lighting, which is based on average total increase.
2/ ECAC rates current as of 1/83: AER=.253, CLMA=.027.
3/ EPD factor is based on $\frac{\text{Prop. Base Increase (4 Cust. Groups)}}{\text{Base SRMC - Current Base Subtotal}} = \frac{557,195}{1,041,682} = .5348983$
/ Average Fuel Cost used in marginal cost calculations is the average offset cost for those groups.
/ Catalina has been spread into the sales and base revenue numbers. Public Auth. & Fringe revenues are contractual.
6/ Columns may not add due to rounding.

TABLE XII-10

ALLOCATION OF AUTHORIZED BASE REVENUE
Test Year 1983
$000

Customer Group	A Sales GWH	B Present Base Revenue	C SRMC Base Revenue	D Increase	E Authorized Base Revenue (B+D)
Domestic	16,588.8	570,749.3	811,192	128,612.6	699,361.9
Lifeline	9,169.5	315,624.4	448,388	71,015.1	386,639.5
Non-lifeline	7,419.3	255,124.9	362,804	57,597.5	312,722.4
Light & Power	16,232.1	509,804.5	817,286	164,471.6	674,276.1
Time-Of-Use	19,061.8	386,816.7	846,344	245,800.8	632,617.5
Agriculture	1,809.6	55,036.3	89,267	18,310.0	73,346.3
Sub-Total	53,692.3	1,522,406.8	2,564,089	557,195.0	2,079,601.8
Street & Area Light	498.7	40,792.9		9,564.0	50,356.9
Total	54,191.0	1,563,199.7		566,758.0	2,129,957.7
Pub. Auth. & Fringe	528.5	2,224.4		0	2,224.4
TOTAL CPUC 1/	54,719.5	1,565,424.1		566,758.0	2,132,182.1

1/ Columns may not add due to rounding.

TABLE XII-11

SUMMARY OF ADOPTED TEST YEAR AVERAGE RATES

Test Year 1983
¢/kWh

Customer Group	Base SRMC	Current Average Rate	Allocated Base Increase	Offset Reduction	Average Authorized Rates	Percent Increase
100						
Domestic	8.668	7.142	.775	(.487)	7.417	3.6
Lifeline 1/	8.668	5.988	.775	(.618) 2/	6.160 2/	2.6
Non-lifeline 1/	8.668	8.677	.775	(.355)	9.112	4.9
Light & Power	8.813	7.664	1.013	(.487)	8.190	6.9
Time of Use	8.218	6.552	1.290	(.487)	7.355	12.2
Agriculture	8.711	7.564	1.012	(.487)	8.089	6.9
Subtotal		7.105	1.038	(.487)	7.651	7.6
Street & Area Lighting		12.703	1.918	(.487)	14.134	11.3
TOTAL		7.156	1.045	(.487)	7.711	7.7

1/ For the purposes of this table, Lifeline and Nonlifeline average rates are actual tariff rates. All other rates are based on Test Year 1983 sales.

2/ Domestic ECAC differentials reflect new rate design (i.e., Lifeline rate equals 80% of system average rate.)

C. Rate Design

1. General

Rate design as used in this portion of our discussion of the pricing of electricity refers to assigning the allocated revenue requirement to the applicable rate charge provisions within each tariff schedule and then setting the precise rate levels within each tariff schedule. Our discussion deals largely with the relatively few aspects of rate design which are at issue in this proceeding.

a. Edison's Rate Design Objectives

Edison states that it attempted to adhere throughout to the following basic principle in making specific rate design proposals for its various tariffs:

> "To reflect marginal costs, essentially all energy rates of each tariff were set at the marginal cost of energy and the balance of the allocated revenue requirement was recovered in other charges in that tariff."

Except for a few schedules, the form of rates and the tariff classifications would not be significantly changed by Edison's proposals. However, Edison has developed proposed tariff schedules in this proceeding which differ in structure substantially from its present tariffs. The fundamental changes to the tariff structure being proposed by Edison are as follows:

> a. The customer charge provision of the tariff schedules has, with some exceptions, been eliminated.[20]
>
> b. The minimum demand charge and demand ratchet provisions of the tariffs have been eliminated.
>
> c. Minimum charge provisions have been established.

---

[20] There is currently no customer charge for residential service.

d. The time-of-use and lifeline energy rate differentials have been established through the ECAC.

e. The tariffs have been restructured to show the effective rates and all applicable base and offset rates on each tariff schedule.

f. The tariff schedules have been structured to provide for the attrition increase proposed to become effective for service rendered on and after January 1, 1984.

g. Various mandatory load management tariff schedules have been proposed.

b. Staff's Rate Design Objectives

The staff states that its rate designs are consistent with the Commission policies enunciated in D.92549 in Edison's last general rate case and in D.93887 in the recent PG&E general rate case. The specific policy the staff cites in D.92549 is "...(1) decreasing no rates; (2) increasing no customer charges, demand charges, or connected-load charges; (3) increasing energy rates only; and (4) eliminating all declining block rates." It cites the following findings of fact in D.93887:

"75. Energy charges are much more responsive to usage than demand or customer charges.

"76. Energy charges provide better conservation signals than demand or customer charges.

* * *

"89. In order to prevent radical changes in rate schedules, all customer and demand charges will not be eliminated at this time.

"90. As discussed earlier in the opinion, customer and demand charges will not be increased."

Except in a few instances where more reasonable results are otherwise obtained, we will adhere in this decision to the policies cited by the staff and to Edison's proposals as enumerated in the preceding paragraphs of this section on rate design.

2. Domestic Rates

a. Minimum Charge

Edison has proposed the establishment of a minimum charge provision of $2 per month, applicable to base-rate charges only. The staff supports this Edison proposal; however, some of the parties take issue with this charge, in particular its applicability to base-rate charges only. The proposal would result in some low-use customers incurring an additional charge amounting to a substantial part of the $2 minimum, even though their bills were otherwise in excess of $2.

TURN takes the position that the minimum charge should apply to the total bill. It opposes a minimum charge which applies only to the base-rate portion of the bill, which it contends would produce additional charges to an unnecessarily high number of customers.

In our opinion the charge would recognize that Edison continues to incur significant costs even when a customer has no, or next to no, consumption. It would allow recovery of some revenue from seasonally occupied or vacation homes, which often have zero monthly billings now that the service charge has been eliminated. We perceive also that the interest of safety would be furthered by such a charge. It would provide an incentive to the owners of unoccupied or unused premises to discontinue electric service. Accordingly, we will authorize a $2 per month minimum charge. Since the minimum bill is imposed in recognition of Edison's fixed costs of service, we

approve application of this minimum charge to the base-rate charges only.

b. Two-Tier vs. Three-Tier Rates

Edison proposes to continue the two-tier (a lifeline tier and a nonlifeline tier) residential base-rate structure we authorized in its test year 1981 rate case. Under Edison's proposed domestic rate design, the nonlifeline tier would be set at full marginal cost and the balance of the allocated revenue requirement would be recovered from the lifeline tier. Edison calculates that this would produce a 4.297¢ per kWh differential between lifeline and nonlifeline consumption, which equates to the second tier being 53% higher than the first. Edison's revised September 1982 residential rates show a 4.279¢/kWh differential between lifeline and nonlifeline rates. This no longer appears to reflect a Tier II set equal to full marginal cost, thus removing the theoretical basis for this differential. Under Edison's proposal, if ECAC changes are made, the cents-per-kWh differential would remain unchanged. Thus, the increasing of ECAC rates would have the effect of decreasing the inversion or percent spread between the two tiers. A decrease in ECAC rates increases the spread.

The staff offered a number of domestic rate designs, both two-tier and three-tier. It noted that there is no a priori reason to recommend a two- or three-tier rate design on the basis of the number of tiers alone. While the staff rate design witness recommends a three-tier rate design, she also provided an alternate two-tier design. The design preferred by the staff rate design witness has three tiers, with the first tier at 9.049¢/kWh, the

second at 10.995¢/kWh, and the third at 13.36¢/kWh.[21] The third-tier proposal represents the staff estimate of average annual on-peak marginal cost for the domestic group. The staff rate design witness noted that this three-tier rate design attempts to link Edison's estimate of residential costs to rates. Edison's load research for residential customers indicate that 15.9% of usage is on-peak, 24.5% is mid-peak, and 59.6% is off-peak. The two-tier rate design provided by staff has a 40% to 50% spread between tiers.

Edison opposes the staff's three-tier rate design. Edison submits that the proposed third-tier rate level has no relationship to third-tier consumption because all third-tier use is not on-peak use. Edison further submits that there is no evidence in this record to support a finding that, from a conservation standpoint, a three-tier rate would be superior to a two-tier rate.

TURN supports a three-tier domestic rate, structured according to the recommendation of its witness, with 35% differentials between tiers, which he believes would have the greatest conservation potential.

CMA believes that narrower tier differentials would produce less conservation than a two-tier structure with a large differential such as Edison's 53% proposal.

The staff points out that although the Commission authorized a two-tier residential rate design in Edison's last ECAC order, D.93895, it reduced the differential between tiers to 37%, down from 43%, which the decision characterized as excessive. The staff rate design witness indicated that, if the Commission is inclined to continue a two-tier rate design for Edison, she would recommend a 40 to 50% differential between tiers.

---

[21] Based on Edison's original proposed revenue requirement of $968 million for the test year and test year 1983 projected average ECAC residential rate of 4.34¢/kWh.

The record in this proceeding provides some support for a three-tier residential rate design for Edison's ratepayers. Under a three-tier rate design both conservation and flexibility in the setting of rates can be enhanced. We are not entirely persuaded that a three-tier rate design is desirable for Edison. We will retain the two-tier residential rate design for Edison, but will continue to examine the applicability of a three-tier structure in Edison's next general rate case.

CVAG entitled a section of its opening brief "Rate Design"; however, it does not treat the subject of rate design or rate design issues. Instead, it deals with the level of the rates requested by Edison.

As we understand CVAG's presentation, insofar as it relates to rate design, it urges that special consideration be given to certain sectors of the population, namely, the elderly and low-income ratepayers and the residents of California's deserts. No basis is provided by this record for providing special consideration to those sectors of the population, other than to maintain the special consideration they now receive through lifeline allowance and other features of the domestic rate schedule.

Leisure World alleges that Edison and the Commission encouraged all-electric residential developments and that through subsequent rate design changes, they have treated the residents harshly. Leisure World contends that these users constitute a separate class of service, and in its opening brief proposes that they be afforded relief as follows:

> "We recommend and urge that those who have a life-line allowance in excess of the basic quantity either be returned to the two-tier schedule for life-line charges or if this is, for any reason, not feasible or lawful, that separate life-line charges be set up at lower rates than the basic life-line charge and dependent on the number of electrical appliances and appurtenances."

The two-tier lifeline rate was ended on January 1, 1981 by D.92549 in Edison's last general rate case. It existed only because lifeline rates were initially established at a time when Edison, unlike other electric utilities in the state, still had a declining block structure. Because of the changes in rate structures (i.e., elimination of declining blocks) which had occurred earlier for other electric utilites in the state, we eliminated the two-tier lifeline rate several years ago for both PG&E and SDG&E. In our opinion, a return to a two-tier lifeline rate would not in any sense promote the intent of the Miller-Warren Lifeline Act or the newly passed Baseline Act.

We can find no basis for treating the occupants of all-electric homes as a separate class of service with a different rate design. They are already provided with a greater lifeline allowance. In our opinion the domestic tariffs we are adopting in this proceeding will provide these users with electric service at fair and reasonable rates.

In allocating the revenues in this proceeding we will establish the first tier of the residential class at 20% below the system average rate. This is consistent with recently enacted Chapter 1541 amending PU Code § 793, which establishes a baseline rate (formerly lifeline rate) at 15% to 25% below the system average rate.

c. <u>Master-Metered Service</u>

Schedule No. DMS-1 applies to master-metered domestic customers who submeter tenants of a multifamily accommodation on a single premises. Schedule No. DMS-2 is a similar tariff for mobilehome park multifamily accommodations. Edison proposes to

change the method of applying the rate schedule discounts[22] from a percentage basis to a flat discount of $2 per month per submetered unit for Schedule No. DMS-1 and $5.95 per month per submetered unit for Schedule No. DMS-2. Edison states that the proposed discounts are based upon the costs which the utility would incur if it were to provide comparable service beyond the master meter to submetered tenants. The staff supports flat rate discounts of the type Edison has proposed for Schedules Nos. DMS-1 and DMS-2.

Western Mobilehome Association (WMA) offered Exhibit 90, which supports Edison's proposed flat rate discount to replace the current 45% discount on all lifeline sales. WMA's evidence indicates that the $5.95 per month per space would approximate the 1983 cost to the master-metered customer. WMA states that it has no objection to Edison's proposal if, in 1984, we make an attrition adjustment to adjust the $5.95 discount to the 1984 cost level. WMA points out that the present percentage discount now affords the mobilehome park owners some protection against rising costs through the operation of the ECAC mechanism.

We will adopt Edison's proposal for fixed rate discounts for Schedules Nos. DMS-1 and DMS-2. In so doing, we are not, however, undertaking to provide any automatic adjustment of this discount for energy costs or attrition. These discounts will be subject to review at the same time that a general revision of Edison's base rates is under consideration.

d. Demand Subscription Service

Edison proposed a mandatory demand subscription service (DSS) offered for the purpose of load control of large residential users. As we have discussed previously, the DSS program is being evaluated in A.82-08-10. Therefore, we will not authorize a DSS

---

22 The discounts are required by Public Utilities (PU) Code § 739.5. The purpose of the discounts is to allow the master-metered customer to recover the reasonable average cost for providing submetered service.

tariff at this time. Funding for DSS will be the subject of a final decision in this rate proceeding.

3. Lighting - Small and Large Power Rates

a. Edison's Proposed Rate Schedule No. GS

Edison is proposing to combine its existing general service Rate Schedules Nos. GS-1, GS-2, and A-7 into a single tariff schedule, Rate Schedule No. GS, which has a Rate A and a Rate B.

The proposed Rate A is an all-energy rate comparable to the present Rate Schedule No. GS-1; however, the customer charge has been eliminated and replaced with a minimum charge.

The proposed Rate B contains both energy and demand charges. The energy charge is separated into two energy blocks; the first energy block is for the first 1,000 kWh, with the rate set equal to the Rate A energy charge. Edison states that the block point of 1,000 kWh was selected in order that the present relationship between the existing GS-1 and GS-2 tariff schedules would be substantially maintained. The second energy block is applicable to all kWh in excess of 1,000 kWh.

Edison states that the proposed demand rate level was developed by first setting the charge for the second energy block of Rate B equal to full marginal energy cost and recovering the remainder of the revenue target amount from the demand charge rate. The rate relationships between the level of charges for Rate A and the second block of Rate B were iteratively adjusted so as to minimize and account for the transfer of customers from Rate B to Rate A. A significant change is the elimination of the minimum demand charge and demand ratchet provisions of the current rate Schedules Nos. GS-2 and A-7. The revenue differences created by the removal of the minimum demand charge and ratchet provision would be recovered from the customers receiving service under the proposed rate Schedule No. GS.

b. Staff Proposal

The staff's proposal would retain Schedule No. GS-1, and it would combine Schedule No. A-7 with Schedule No. GS-2. In Exhibit 88, the staff describes its proposal as follows:

> "The proposed base revenue increase was spread on a uniform ¢/kWh basis to each tariff schedule. The revenue impact due to incentive payments for Automatic Powershift was included in the revenue requirement for Schedule No. GS-2. The existing Schedule No. GS-1 was retained except the $4.50 Customer Charge was eliminated and a $5.00 Minimum Charge employed. Schedule No. GS-2 combines existing Schedules Nos. GS-2 and A-7. Proposed Schedules Nos. GS-1 and GS-2 were designed separately so that the average base rates could be brought closer together without creating radical changes."

Staff believes that its proposed rate design is consistent with Commission policy as expressed in Edison's and PG&E's last general rate decisions, D.92549 and D.93887, respectively. In D.92549 we adopted the following guidelines for rate design: (1) decrease no rates; (2) increase no customer charges, demand charges, or connected-load charges; (3) increase energy rates only; and (4) eliminate all declining block rates. We indicated that these guidelines would provide a meaningful step toward greater energy conservation and at the same time promote equity within and among customer groups. For Schedules Nos. GS-1, GS-2, and A-7, we retained a minimum demand charge but changed the declining block energy charge into a single block rate for Schedules Nos. GS-2 and A-7.

In D.93887 we recognized that energy charges provide a better conservation signal than customer and demand charges. Although we did not eliminate all customer and demand charges at that time, we chose not to increase them.

Staff also points out that Edison's own rate design goals are to eliminate most customer charge provisions, eliminate minimum demand charge and demand ratchet provisions, and establish a minimum charge provision.

TURN supports the staff proposal because it provides a more nearly uniform rate for the GS-1 and the GS-2 groups. TURN contends that the record provides no reasonable basis for Edison's proposal, which TURN maintains would charge the small general service customer almost five cents more per kWh than the large customers.

Edison asserts that the staff's proposal on Schedules Nos. GS-1, GS-2, and A-7 fails to consider the economics of each rate. Edison contends that the staff rate design would cause all customers with a load factor greater than about 13% to shift to the demand rate (Schedule No. GS-2), regardless of their energy consumption. Edison believes that 80 to 90% of these customers have load factors in excess of 13% and that, therefore, they would all require demand meters. Edison submits that maintaining a simple rate structure based solely on energy use for these small customers is much more economical and would avoid the potential of installing up to 200,000 additional demand meters.

We reject Edison's proposed schedules because Schedule B effectively is a declining block rate. Such a design is clearly contrary to Commission policy. Instead, we have decided to adopt a rate design which consolidates the existing GS-2 and A-7 schedules, as proposed by staff. We will allocate a larger share of the revenue requirement to the GS-2 energy rate, to reduce the differential between it and the higher GS-1 energy rate. This reduces the tendency for customers currently on the GS-1 schedule to shift to a GS-2 schedule. More significantly it is consistent with our policy to bring energy rates toward marginal cost to discourage wasteful, uneconomical use. In addition, we will establish a $100 minimum charge for GS-2 customers to further reduce movement from

GS-1 to GS-2, in order not to place an unreasonable burden on Edison to purchase and install large numbers of demand meters.

c. Christian Science Churches

D.92549 in Edison's last general rate case stated:

> "The showing of the Christian Science Churches in this proceeding clearly demonstrates the need for the development by Edison of optional tariff offerings such as are afforded by the Schedule No. A-12 demand rate and the Schedule No. A-1 nondemand rate of PG&E. The order herein will direct Edison to work with our staff toward developing such an alternative offering."

Somehow, this order was never properly implemented. The record in this proceeding shows that today the Christian Science Churches are still caught in the same circumstances, i.e., high demand charges disproportionate to their cost to the utility system because of their unavoidable usage characteristics.

Christian Science Churches urges in this proceeding that we adopt the following language as contained in Edison's proposed Schedule No. GS: "Rate Selection: Rate A or Rate B is applicable at the option of the customer."

While we are not adopting Edison's proposed Schedule No. GS, the adopted schedules provide similar relief, since rate Schedules Nos. GS-1 and GS-2 are applicable at the option of the customer.

4. Time-Of-Use Rates

a. Edison's Proposal

Edison proposes to revise Rate Schedule No. TOU-8 to reflect the following:

> "(a) An increase in the demand charges, (b) An increase in energy rates, set at full average marginal energy cost, (c) Redesign of the energy rates to have a flat base rate

energy charge with all time-period energy rate differentials being established through the application of the energy cost adjustment billing factors (ECABF). The proposed methodology would establish future ECABF maintaining a 0.580 cents per kilowatthour differential between on-peak and mid-peak and a 0.450 cents per kilowatthour differential between mid-peak and off-peak total average energy charges. The differentials in energy charges were determined based on the differential in marginal energy costs between these time periods, and (d) Removal of the minimum demand charge and the ratchet-clause provision of the tariff, with the resultant revenue deficiency being collected from Schedule No. TOU-8 customers."

Edison does not propose to modify the presently effective seasonal time periods and demand charge differentials at this time. Edison states that: (a) it does not have sufficient information concerning the effect of the present Schedule No. TOU-8 rate structure upon those customers with demands in the range of 500 kW to 1,000 kW because Schedule No. TOU-8 was expanded to include those customers as of January 1, 1981; (b) such a change could have a material cash-flow impact; and (c) some seasonality is created by the fact that ECAC rates fluctuate on a seasonal basis.

b. Staff Proposal

The staff has presented two rate designs for Schedule No. TOU-8. Both designs reflect full marginal costs for on-peak rates. The design favored by the staff retains present customer and demand charges. Unlike Edison which proposes for Schedule No. TOU-8 an increase in on-peak and mid-peak demand charges, the staff would maintain TOU-8 demand charges at current levels and assign to the energy charges the entire TOU-8 revenue increase. The staff's

alternative design retains only the present customer charge and includes a relatively low demand charge of $1 per kW, which is intended to recover distribution-related costs on a nontime-differentiated basis. The staff states that both of its TOU-8 rate designs would produce strong economic signals to shift consumption from on-peak to mid-peak and off-peak periods. It states that the alternative rate design has been presented in response to the Commission's findings of facts 75 and 76 in D.93887: "Energy charges are much more responsive to usage than demand or customer charges.", and "Energy charges provide better conservation signals than demand or customer charges." The staff regards its alternative rate design as a radical change from the existing TOU-8 tariff schedule and, therefore, does not recommend it.

The staff supports the following aspects of Edison's TOU rate proposal:

1. Elimination of existing minimum demand charge and demand ratchet provisions.
2. Retention of existing time periods.
3. Level base energy rates and establishment of time period rate differentials in the ECABFs.
4. Nonimplementation of seasonal rate differentials at this time.

The staff also supports Edison's proposals for experimental TOU rate schedules.

c. <u>CIEC</u>

CIEC, as well as the other industrial parties, express concern over the staff's proposed treatment of the demand charge. CIEC asserts that it is improper to recover essentially fixed costs by way of the energy charge. CIEC also emphasizes that the demand charge, particularly a time-differentiated demand charge, is the most

effective signal to customers to maintain level loads, particularly as that charge has been refined under the TOU concept.

CIEC takes the position that the Edison proposal, by incorporating an increase in the TOU-8 demand charge, will preserve and reinforce the demand charge concept and that, conversely, the staff's proposal will subvert that concept by assigning no increase to the demand charge. According to CIEC, the effects on Edison of adopting the staff proposal would be unstable revenue and deterioration of load factor, with the ultimate consequence being a higher cost per kWh for all customers.

d. CMA

CMA supports Edison's proposed TOU-8 schedule because it believes that the schedule would encourage conservation and economy by means of its distribution of base costs through the demand charge. CMA points out that Edison's proposal to increase its time-differentiated demand charges will cause the base costs generated by TOU-8 customers to be charged to them directly, and not as a function of energy costs. CMA asserts that there is clear evidence on this record that the demand charges have affected conservation, and thus they should be retained for allocation of TOU base costs.

CMA asserts, however, that the TOU differential in Edison's energy cost component on the TOU-8 rate schedule contains serious flaws. CMA's witness, in his testimony, contends that Edison's overestimation of its fuel costs and unrealistic estimate of its system heat rates for test year 1983 invalidate Edison's time period cost estimates. It is CMA's position that differentiated energy rates cannot be implemented on the basis of the evidence.

e. CRA

CRA believes the TOU-8 energy rate should be set equal to full marginal cost. CRA introduced into evidence a specific proposal for the TOU-8 rate, and further advocated certain general principles to guide the design of the A-7 rate.

With respect to the TOU rate, CRA asserts that it is appropriate to set the energy charges at their full marginal cost in each time period, and to recover the remainder of the required revenue through the demand and customer charges. As CRA's witness explained in presenting Exhibit 96, the purpose of this use of marginal energy costs is as follows:

> "This treatment is appropriate, in my opinion, because the structure of the time-of-use energy charges closely approximates that of marginal energy charges. Furthermore, there is a much more immediate cost response to the consumer's decision to save a kilowatt-hour of energy than there is to his decision to shave a kilowatt of peak load. The requirement to produce a kilowatt-hour at 10 a.m. on a July morning means that the utility must operate a generator and consume fuel at 10 a.m. on that July morning. The marginal savings which Edison might realize from a reduction in the consumer's peak load on that same day may not materialize for another five to ten years. Thus, I would advocate setting TOU energy charges at their full marginal cost level even if it were not possible to collect all marginal capacity costs in the demand charge."

For the A-7 rate, CRA recommends the energy, demand, and customer charges be set at approximately equal proportions of their respective costs. CRA believes that this treatment is appropriate for a non-time-differentiated rate. According to CRA, since the energy charges do not vary from peak to off-peak period, a charge set equal to peak marginal energy cost would overstate the cost for electricity used in mid-peak and off-peak periods. This, CRA submits, would produce a result unfair to customers, and it would be a departure from the goal of efficiency which underlies the use of marginal costs in the first place.

f. <u>Adopted Time-Of-Use Rates</u>

We are adopting the staff's recommended time-of-use proposals which are consistent with our present rate design policy. In addition, we believe that it is desirable to expand optional time-of-use rates to customers with demands of less than 500 kW. To accomplish this, we are requesting Edison to work with our staff to develop and file a plan for expansion of Schedule No. TOU-GS. The expanded program should include the larger General Service customers and add at least 1,000 TOU meters per year to the system. Another of our concerns regarding time-of-use rates is the erosion of rate differentials by time periods due to ECAC changes. Therefore, for future ECAC proceedings we are directing Edison to maintain the approximate ratios in Schedules Nos. TOU-8, TOU-PA-1, and TOU-GS and the approximate differentials in experimental time-of-use schedules authorized by this decision.

5. <u>Agricultural and Pumping Rates</u>

a. <u>Edison's Proposal</u>

The present Rate Schedule No. PA-1 was designed to offer an energy rate and a connected load charge of $1 per month of connected horsepower. Edison's proposed rate design would increase the connected load charge to $1.30 per month and increase the energy charge, so as to maintain the present relationship with Rate Schedule No. PA-2 to prevent customer switching.

Rate Schedule No. PA-2 includes both an energy charge and a demand charge. Under Edison's proposal, a base-rate minimum charge of $5 per month would be established, and the demand charge and energy charges would be increased to maintain the present relationship with Rate Schedules Nos. PA-1 and GS. The minimum demand charge and ratchet provisions of the tariff would be eliminated, and the resultant revenue deficiency recovered from Schedule No. PA-2 customers.

b. Staff Proposal

The staff notes that there is little difference between its agricultural and pumping rate design and that of Edison. The base revenue increase would be spread on a uniform cents-per-kWh basis to each tariff schedule. For Schedule No. PA-1, the service charge would not be increased; instead, the entire increase would be applied to the energy charge. For Schedule No. PA-2, the demand charge would not be increased, and again the entire increase would be applied to the energy charge.

c. CFBF

(1) Rate Schedules Nos. PA-1 and PA-2

CFBF supports the staff proposals regarding both Schedule No. PA-1 and Schedule No. PA-2. It agrees that any revenue increases for the agricultural class should be passed on through increased energy charges.[23] For Schedule No. PA-2, CFBF urges that the demand charges remain $3.75 per month and should be assessed for each kW, without a minimum level of 75 kW and for Schedule No. PA-1 that the service charge remain $1 per horsepower.

CFBF contends that if the Schedule No. PA-1 service charge is increased, the off-peak credit should also be increased. Schedule No. PA-1 contains an off-peak credit which reduces the monthly service charge by 50¢ per horsepower of connected load. To obtain this credit customers must agree to permit Edison to have installed, at the customer's expense, an automatic disconnecting device designed to prevent use from 8 a.m. to 10 p.m. on weekdays. CFBF maintains that the ratio between the credit and the charge should be maintained, i.e., if the service charge is increased, the credit should be increased in proportion.

Our understanding of Edison's agricultural rate design is that customer switching was considered to the extent that it was necessary to raise demand charges and that only to the extent

[23] The position of CFBF is that any revenue increase to the agricultural class should be recovered through energy charges only.

that the revenue requirement could be met through increasing energy charges to the marginal cost.

As to CFBF's proposal that the off-peak credit for Schedule No. PA-1 should be increased, there is no cost justification for this increase in this record. Neither Edison nor the staff made such a proposal, and CFBF presented no evidence supporting such a change.

Again, the staff has proposed rates that are consistent with our present rate design policy, and we will adopt its proposal.

(2) Agricultural TOU Schedules

Edison proposes to expand its agricultural load management program by placing 500 additional farmers on TOU rates during 1983 (Exhibit 12). We will adopt this proposal which is supported by CFBF, as well as the staff. As they point out, the agricultural TOU program has a positive benefit-cost ratio. CFBF states that it recognizes the need for expansion of the voluntary agricultural TOU schedules and that it will continue to cooperate with Edison in promoting their implementation.

XIII. Findings and Conclusions

A. Findings of Fact

1. The adopted results of operations for test year 1983 and each element thereof, as shown in Table X-2, provide a proper and reasonable basis for determining Edison's California jurisdictional base-rate revenue requirement.

2. The proper and reasonable level of Edison's California jurisdictional base-rate revenue requirement for 1983 is $2,132,182,100.

3. Present base-rate revenues are estimated to produce $1,565,424,100 in 1983.

4. The level of gross revenues produced by Edison's present base rates for electric service will not recover Edison's revenue requirement in the test year 1983.

5. The cost of service for Edison's Catalina Island electric service is appropriately included in Edison's total California jurisdictional cost of service.

6. Estimated revenues based on the sales forecast for test year 1983 and attrition year 1984 are subject to significant fluctuation.

7. Because of the difficulties inherent in estimating test year electricity sales and the need to protect the ratepayer and the utility from an incorrect estimate, it is reasonable to establish an ERAM for electric sales beginning January 1, 1983.

8. The purpose of ERAM is to adjust base rate and AER revenues for changes in revenue due to unexpected fluctuations in sales during the test period, either in total sales levels or in the distribution of kWh sales among different tariff schedules.

9. Factors contributing to inaccuracy in estimating electricity sales are the difficulties in quantifying the effects of conservation, rate design, weather, the economy, and the gain or loss of a large utility customer.

10. The adoption of an ERAM will minimize any disincentives for Edison to promote cost-effective conservation programs and rate design policies.

11. A return on equity of 16.00% is fair and reasonable for the test year 1983 and attrition year 1984.

12. A 12.55% rate of return for the test year 1983 and a 12.65% rate of return for the attrition year result from the following capital structure and capital costs, which are fair and reasonable:

	Capital Ratio %	Cost %	Weighted Cost %
Test Year 1983			
Long-Term Debt	46	10.42	4.79
Preferred Stock	12	8.63	1.04
Common Equity	42	16.00	6.72
Total	100		12.55
Attrition Year 1984			
Long-Term Debt	46	10.59	4.87
Preferred Stock	12	8.81	1.06
Common Equity	42	16.00	6.72
Total	100		12.65

13. A 16.00% return on equity will provide after-tax interest coverage of about 2.62 times over the two-year period, which should allow Edison to retain its current bond ratings.

14. To earn an average rate of return of 12.55% in 1983, Edison's base rates for California jurisdictional electric service should be increased effective January 1, 1983 to provide an increase in base-rate revenues of $566,758,000 and should be further increased effective January 1, 1984 to provide for an attrition allowance to cover additional increases in cost of service for 1984.

15. The rate of return on rate base together with the other components of the increased base-rate revenue requirement are found

to be justified and are authorized with the understanding that under the Rate Case Processing Plan, the next earliest test year to be used for establishing Edison's revenue requirement will be 1985.

16. It is reasonable to revise the AER in recognition of the newly authorized rate of return adopted in this decision.

17. Edison's consistent use of a linear trend equation to estimate the recurring portions of operation and maintenance (O&M) expenses based on expenditures recorded in 1976 through 1980 is overly simplistic and overestimates reasonable 1983 expense levels.

18. Our staff's use of a linear trend to estimate O&M expenses if the result meets the statistical criteria established by staff is reasonable.

19. The use of historic averages of O&M expenses when trending results do not meet staff's statistical criteria is reasonable.

20. There is a need to develop forecasting methods which better match the type of growth expected for various subparts of total O&M expenses.

21. In developing nonlabor escalation rates, it is reasonable to rely on the fall of 1982 Data Resources, Incorporated (DRI) forecast, the latest available forecast at the time of this decision.

22. Reliance on the DRI Trendlong scenario in the fall of 1982 DRI forecast is reasonable in adopting nonlabor escalation rates.

23. The labor escalation rate applicable to Edison's union employees in 1982 is reasonable.

24. Application of the 1982 labor escalation rate to nonunion employees is reasonable.

25. For 1983, it is reasonable to use the most recent Trendlong forecast of DRI in determining the labor escalation rate for union and nonunion employees.

26. A rate of escalation of 4.3% for nonlabor and 9.0% for labor in 1982 is reasonable for the purpose of determining Edison's level of expenses for 1983.

27. An escalation rate of 5.4% for nonlabor and 6.1% for labor in 1983 is reasonable for the purpose of determining the 1983 level of expenses.

28. Authorization for recovery of deferred maintenance expense would effectively guarantee that a utility could earn or exceed its authorized rate of return, regardless of its operating efficiency or inefficiency simply by curtailing current maintenance activities.

29. It is reasonable to disallow all recovery of deferred maintenance expense.

30. Cost overruns in steam production overhaul expenses can be caused by factors such as inflation higher than expected and poor cost estimates in addition to the unpredictable component which Edison defines as Class III overhaul work.

31. Edison has instituted a major program to improve estimations of overhaul expenses, and has developed improved procedures over the last two years.

32. Edison's improved budgeting efforts should allow greater accuracy in forecasting Class I and Class II overhaul expenses and a resulting reduction in the historically high overruns.

33. The funding provided in the test year revenue requirement for steam production overhaul expenses excluding fuel represents a 32% increase per overhaul from the historical average in constant dollars and is reasonable.

34. For other power generation expense excluding fuel, it is reasonable to adopt one-half of Edison's estimate of expenses for 1983 Class III overhaul activities.

35. Staff's reliance on the level of expenses in the years 1979 and 1980 in determining combined cycle O&M expenses underestimates planned maintenance expenses for combined cycle units for 1983.

36. Edison's analysis of combined cycle expenses for 1983 is reasonable and supports the adoption of Edison's requested funding level.

37. It is reasonable to allow Edison to recover its actual expenditures in the abandoned fuel cell project based on a review of Edison's decision to pursue and subsequently abandon the project.

38. Recovery of AFUDC on commercial projects is allowed once the plant is placed in rate base as used and useful.

39. Research and development of new energy technologies are more risky than normal utility activities.

40. Recovery of AFUDC on a research, development, and demonstration project may be allowed only after a project is extensively scrutinized for reasonableness.

41. Edison's decision to wait until this rate case to request amortization of fuel cell project expenses, when direct charges were last made at the start of 1979, was imprudent.

42. It is reasonable to disallow recovery of AFUDC accumulated after the end of 1980 for the abandoned fuel cell project.

43. It is reasonable to amortize fuel cell project costs plus the amount of AFUDC allowed in this decision over a four-year period.

44. The damage sustained by SONGS Unit 1 due to corrosion of water tubes was extraordinary.

45. The record in this proceeding clearly establishes that SONGS Unit 1 was not expected to experience the corrosion of water tubes caused by intergranular attack during its operational life.

46. The cost to repair the steam generator tubes at SONGS Unit 1 was $70.8 million of which Edison bears 80%. The remaining 20% is borne by SDG&E.

47. SONGS Unit 1 has operated at reduced capacity following its repair.

48. It is unclear from the record whether Edison is foreclosed from recovering monetary damages from Westinghouse, the supplier of the steam generators at SONGS Unit 1.

49. It is reasonable to permit Edison to recover its share of the sleeving expenditures at SONGS Unit 1 over a four-year

amortization period, subject to refund pending further analysis of the prudency of Edison's conduct in regard to its potential legal remedies relating to such expenditures.

50. The sleeving activity at SONGS Unit 1 constituted a repair which restored the serviceability and maintained the life of the steam generator.

51. Since SONGS Unit 1 has not been operating at full capacity since it has been brought in line, the sleeving cannot be considered to have enhanced or added to the plant's operating life.

52. It is reasonable to treat the sleeving cost as extraordinary maintenance expense.

53. Spent nuclear fuel disposal costs refer to the costs of either reprocessing or permanent disposal.

54. It is reasonable to allow prior recovery in base rates of projected expenses associated with permanent disposal of spent nuclear fuel.

55. The revenue requirement associated with spent nuclear fuel disposal costs is determined by using a straight-line method of recovery based on the remaining life of the nuclear plant.

56. In isolating spent nuclear fuel costs it is reasonable to identify the accrual and rate base components as line items in the Summary of Earnings.

57. By adjusting revenues for the recovery of spent nuclear fuel costs to be net instead of gross of tax, there is a better matching of the costs of nuclear fuel disposal with the benefits of nuclear power.

58. Staff's treatment of taxes for spent nuclear fuel costs is reasonable.

59. During the period 1979 through 1981, the workload of customer service representatives increased at the same time that the number of representatives decreased.

60. Edison's request for additional labor expense to increase the number of customer service representatives is reasonable.

61. Because neither the company's nor the staff's estimates of nonlabor expense for Customer Accounts 903 and 905 are statistically significant, it is reasonable to adopt a method which recognizes the average historical cost per customer in determining the nonlabor expense component for these accounts.

62. It is reasonable to exclude expenses for the cost of ongoing equal employment opportunity litigation pending the final disposition of this litigation.

63. Consistent with D.93887 for PG&E, it is reasonable to maintain public awareness activity at 1980 expense levels.

64. The insurance premium for nuclear replacement energy is the type of cost that is appropriately recovered through base rates because it is a fixed charge not directly attributable to an energy source.

65. Consistent with the policy adopted in D.93887 for PG&E and D.92892 for SDG&E, it is reasonable to exclude all dues to the Edison Electric Institute.

66. It is reasonable to exclude expenses for contributions made to organizations which do not provide direct benefits to ratepayers.

67. Consistent with D.93887 for PG&E, it is reasonable to disallow expenses associated with the cost of cleanup of Three Mile Island.

68. The disallowance of all expense associated with a management audit is reasonable since no audit is planned during 1983 or 1984.

69. Edison's estimate for office alterations expense was supported in the record and is reasonable.

70. An allowance for recovery of estimated costs of major projects which may be abandoned during the test period would provide no opportunity to review the prudency of abandoned project costs before rate recovery was granted.

71. By allowing the company to recover estimated abandoned project costs, the company would be collecting funds for abandonments that may never occur.

72. In D.92549 for Edison, the Commission declined to adopt a methodology to recovery estimated costs of major projects which may be abandoned during the test period.

73. It is not reasonable to allow recovery of estimated costs for major projects which may be abandoned during the test period.

74. It is reasonable to allow recovery of Edison's estimated abandonment costs for small projects which are of the type which are typically abandoned during a given year.

75. Staff's methodology for estimating the expense associated with Edison's stock purchase plan significantly underestimates this expense. It is therefore reasonable to adopt Edison's estimate of the stock purchase plan expense.

76. A staff estimate of the rate of increase of expense associated with the dependent medical plan is more realistic than Edison's because it better reflects current rates of escalation.

77. It is reasonable to adopt a budgetary approach instead of trending for Accounts 920, 921, 930.1, and 932 where additional growth in the trended portions of these accounts cannot be justified.

78. By recognizing the shift to operational activities from construction activities and by providing additional operational funds in the accounts cited in Finding 77, it is not necessary to provide an expense for more growth in these accounts.

79. The use of historical averages in projecting the depreciation expense associated with negative net salvage is reasonable where the company's estimate was not statistically significant.

80. The ERTA requires the normalization of tax benefits of ACRS depreciation and ITC if Edison is to be eligible to use these tax benefits.

81. Since the net salvage method is an appropriate method to use in determining depreciation rates for test year 1983, it is reasonable to exclude the cost of removal from federal income tax deductions for the 1983 test year in conformance with the normalization requirements of ERTA.

82. ERTA contains no prohibition that normalization during the transition period cannot benefit ratepayers.

83. News Release IR-82-25 specifically requires that the normalization of the difference between ADR and ACRS for 1982 be recorded on Edison's books of account in a deferred tax reserve. The balance in this account is a logical beginning balance to use in computing the average deferred taxes from depreciation to deduct from rate base for the 1983 test year.

84. Although SONGS Unit 2 has not yet been included in cost of service for ratemaking purposes, it has met IRS requirements for plant in service in 1982.

85. Since SONGS Unit 2 is not yet included in rate base, the rates set in this proceeding do not recognize the tax benefits associated with SONGS Unit 2.

86. Until SONGS Unit 2 is placed in rate base it is reasonable in this case only to normalize the ACRS and ITC associated with plant and to require Edison to place these benefits for 1982 in a deferred tax reserve.

87. The requirements of the Tax Equity and Fiscal Responsibility Act must be recognized in determining the company's revenue requirement.

88. A number of RD&D programs particularly under the category of environmental assessment contain the questionable objective of avoiding or mitigating environmental regulation.

89. It is reasonable to disallow one-third of the proposed funding for the programs which contain the objective described in Finding 88.

90. Edison requests funding for many RD&D programs which appear to provide no special benefits to Edison's service territory.

91. Since Edison is funding projects which are also being undertaken by private industry and research organizations, Edison's funding of similar projects may be duplicative.

92. It is reasonable to reduce Edison's requested budget by one-half for projects which are more broadly geared to industry in general and which are currently being funded by other organizations.

93. It is reasonable to disallow entirely the proposed expenditure on the Electric Vehicles program since it promotes increased demand for electric service.

94. There is no justification in the record of this proceeding for the sharp increases for individual RD&D programs which Edison has requested.

95. It is reasonable to apply a 20% across-the-board cut to RD&D programs, exclusive of outside research.

96. Consistent with D.93887 for PG&E, it is reasonable to provide funding to EPRI at the level established by EPRI's actual billing to Edison for 1982.

97. Edison has complied with the conservation-related requirements imposed in D.92549 such that no penalty is warranted.

98. Consistent with D.93887 for PG&E, it is reasonable to give Edison management discretion to reallocate base rate funds in amounts up to $2.5 million among individual conservation and load management programs, as long as funds are not reallocated to or from the three major categories of Residential Conservation, Nonresidential Conservation, and Load Management without prior Commission approval.

99. It is reasonable to allow the carry-over of unspent conservation and load management funds to the following year to supplement that year's budget allotment, and to give Edison management discretion to allocate the unspent funds without prior Commission approval if they are no more than $2,500,000 and if funds are not reallocated to or from the three major categories.

100. It is appropriate that Edison be directed to report by February 15 of each year on its conservation and load management expenditures during the prior year and its proposed budget for the current year.

101. For those conservation and load management program expenses which are funded through base rates, as opposed to funding through a balancing account, a 20% discount across-the-board cut is reasonable.

102. It is reasonable to allow Edison to recover $3.5 million through rate design in 1983 for new load management program incentive payments allocated among customer classes in the manner set forth in this decision.

103. For the attrition year, it is appropriate to escalate the expense portion of approved conservation and load management programs consistent with the attrition procedure established in this decision.

104. It is reasonable to allow Edison discretion to allocate the authorized amount of load management air-conditioning cycling equipment costs between the residential and nonresidential programs.

105. All but two of the conservation programs for which energy savings have been quantified clearly meet the utility cost-effectiveness test.

106. Since the Conservation Corner does not meet the utility cost-effectiveness test, it should be phased-out as quickly as is feasible in 1983.

107. Since the Residential New Construction program fails the utility cost-effectiveness test, it is reasonable to deny funding for this program.

108. It is reasonable to structure the Conservation Planning Centers program to increase cost-effectiveness.

109. Rate-base instead of expense-type treatment of load management equipment costs should be assumed in evaluating cost-effectiveness.

110. Nonquantifiable benefits of conservation and load management programs should be considered in determining whether a program should be authorized.

111. The overlap between Regulatory Support and Management/Administrative Support categories makes it difficult to evaluate the magnitude and reasonableness of regulatory support and other support activities.

112. The Commercial/Industrial New Construction program should be continued in 1984 only if 1983 results are promising.

113. Nonprogram-specific advertising and informational activity is discouraged since it is difficult to associate energy savings with this activity.

114. Consistent with D.82-11-086 in A.61067, it is reasonable to authorize RCS funding at $5 million. This amount is more appropriately recovered through the Conservation Load Management Adjustment Clause balancing account rather than through base rates.

115. It is reasonable to disallow Edison's proposed funding for the Solar Marketing program which is already provided for through the OII 42 proceeding.

116. Staff's disallowance of funding for rebates for solar retrofits to multifamily units and to residential homes occupied after January 29, 1980 is consistent with the decisions in OII 42.

117. It is appropriate to limit Edison's heat-pump water heater programs to homes in areas where natural gas is not available or, for retrofit installations, to customers who are unable to use solar systems.

118. Consistent with D.93887, it is reasonable to reduce the level of conservation public awareness and advertising expenses.

119. There ~~is~~ a need to determine externality costs and benefits of conservation and load management programs, and a need to more carefully measure the utility system savings associated with particular load management programs.

120. Due to the large scale of the C/I Air-Conditioning Cycling Program, expense treatment is not proper.

121. There is a need to evaluate whether load management incentive payments should be treated as transfer payments recovered

through rate design or as program costs, as discussed in this decision.

122. It is appropriate to consider funding for the DSS program when and if the program is approved.

123. Edison indicated in A.82-08-10 which has been consolidated with this proceeding, that it now plans to install only 10,000 residential air-conditioning cyclers in 1983. For this reason, a downward adjustment in funds for this activity is reasonable.

124. Edison's proposal to regulate swimming pool pumps by means of radio-controlled devices in lieu of compliance with the CEC Load Management Standards program and tariff Rule 14.1 is not reasonable. The staff adjustment for the swimming pool program is therefore proper.

125. CCJCA has not provided sufficient detail of its proposals to warrant their adoption at this time.

126. The adopted level of funding for Edison's conservation and load management programs is reasonable.

127. During 1980, 1981, and part of 1982, Edison has been extremely reluctant to sign contracts with QFs at full avoided cost.

128. Since April of 1981 through early 1982 Edison had adopted a policy not to make standard offers to QFs based on full avoided cost.

129. Edison's pricing policies during 1980 and 1981 had a chilling effect on the development of QF resources within Edison's service area.

130. Edison's pricing policies during 1980 and 1981 were contrary to the express policies set forth by this Commission.

131. Edison has been under a duty to exercise its best efforts to pursue and develop cogeneration and small power production resources using avoided cost principles.

132. QFs have complained to the Commission staff of Edison's refusal to make full avoided cost offers.

133. Edison continued its pricing policies of not offering full avoided cost contracts to QFs into 1982 as indicated by D.82-04-071.

134. Edison's pricing policies to QFs undermine Edison's stated goal to bring on line 2,100 MW of alternative and renewable resources by 1990.

135. A penalty at a dollar level equivalent to 10 basis points on Edison's return on equity in 1983 and 1984 is justified and reasonable for failure to comply with the avoided cost policies of this Commission.

136. It is reasonable to reduce gross operating revenues by $3.9 million in test year 1983 and $4.1 million in attrition year 1984, which represents the revenue equivalent of a 10 basis point penalty on Edison's return on equity in 1983 and 1984.

137. The attrition allowance in 1984 can be reasonably segregated into an indexed component and a fixed component.

138. The indexed component of the attrition allowance consisting of the amount of test year 1983 labor and nonlabor O&M expenses subject to escalation is reasonable.

139. Quantification of the indexed component of the attrition allowance by application of an indexing formula reflecting the fall 1983 DRI forecast of escalation rates to the test year 1983 labor and nonlabor O&M expenses is reasonable.

140. Property insurance expense is properly included in the indexed component of the attrition allowance.

141. The fixed component of the attrition allowance consisting of depreciation, ad valorem tax, income tax, and return on rate base is reasonable.

142. Staff's method of calculating plant additions during the attrition year is reasonable.

143. In order to avoid further hearings to adopt an attrition allowance, it is appropriate to use the staff's 1983 estimate for working cash allowance for 1984.

144. Staff's method for determining capital related costs in the attrition year is reasonable.

145. The attrition rate adjustment procedure set forth in Section XI and Appendix E of this decision is reasonable.

146. The jurisdictional cost allocation method employing average costs, as used by Edison and the staff, is reasonable.

147. Edison's calculation of the net-to-gross multiplier is reasonable.

148. Consistent with prior decisions the use of marginal cost for electric rate design is appropriate.

149. Marginal costs are defined as the change in total costs which result from a change in output.

150. Embedded cost of service reflects historical construction costs and depreciation of existing plant which are not relevant to current costs of meeting changing demand of electric service.

151. Embedded cost of service, although a factor to be considered in setting rates, is not an appropriate measure for determining the conservation impact of a particular rate design.

152. It is equitable that changes in electric rates for each major customer group reflect the cost to the utility of furnishing the last increment of additional system supply.

153. Directing rates for each major customer group toward the cost to the utility of furnishing an additional unit of system supply will provide appropriate signals to customers as to the cost of added energy consumption and will provide the appropriate incentive for conservation.

154. Marginal costs provide the acceptable approach to allocating cost recovery among customer groups because they provide a clear pricing signal relating to a customer's conservation measures and are in keeping with federal standards.

155. Application of marginal costs for allocation of adopted cost recovery by customer group should be tempered by judgment and experience rather than simply relying on a statistical approach.

156. For retail electricity rates, a short run marginal cost methodology is appropriate.

157. There can be three means of calculating marginal costs: (1) short run energy and short run capacity, (2) short run energy and long run capacity, and (3) long run energy and long run capacity.

158. For ratesetting purposes, consumers should be signaled the present cost of consumption.

159. Short run energy and short run capacity costs are the correct way of conceptualizing marginal costs for ratesetting.

160. Consistent with D.93887 for PG&E, it is appropriate to annualize the capital cost of the combustion turbine using a real economic carrying charge rather than a levelization factor, to better reflect the concept of short run marginal costs.

161. Although it is proper to include transmission and distribution costs in determining short run marginal costs as a basis for retail rates, the record is insufficient to establish transmission and distribution shortage costs at this time.

162. The adopted test year marginal costs and incremental heat rates are reasonable.

163. It is appropriate to use the EPD method to allocate the revenue requirement among customer classes.

164. Although the allocation of revenue using a total revenue requirement to determine a total effective rate is desirable, the record is insufficiently developed to adopt such an allocation.

165. A minimum charge applicable to domestic base rates allows recovery of fixed costs which are incurred even when a customer has little or no consumption.

166. A minimum bill of $2 per month will compensate for the benefits received by zero and near-zero consumption residential customers.

167. The minimum charge is reasonably applied to the base rate portion of the bill to allow Edison to recover its fixed costs of providing service. The minimum charge is not intended to recover the cost of fuel and purchased power.

168. The record in this proceeding is insufficient to justify a change at this time from a two-tier to a three-tier residential rate design.

169. It is reasonable to apply the discounts in Schedules No. 1, DMS-1, and DMS-2 on a flat discount basis rather than on a percentage discount basis, where the flat discount level is comparable to the costs which the utility would incur if it were to provide comparable service beyond the master meter to submetered tenants. The flat rate discounts, however, should not be adjusted for revised energy costs or attrition.

170. The staff proposal to retain Schedule No. GS-1 and to combine Schedule No. A-7 with Schedule No. GS-2 is consistent with the rate design policies adopted in prior Commission decisions.

171. It is reasonable that either Schedule No. GS-1 or Schedule No. 2 should be applicable at the option of the general service customer.

172. A minimum charge of $100 is appropriate to mitigate the transfer of customers from Schedule No. GS-1 to Schedule No. GS-2.

173. It is reasonable to expand Schedule TOU-GS to allow a larger number of customers to participate.

174. Staff's proposal to retain Schedule No. TOU-8 demand charges at current levels and assign to the energy charges the entire TOU-8 revenue increase is consistent with the rate design policies adopted in prior Commission decisions, and is reasonable.

175. Staff's proposal to maintain the connected load charge and increase the energy charge under Schedule No. PA-2 is consistent with prior Commission decisions, and is reasonable.

Conclusions of Law

1. Edison should be authorized to file the revised electric rates which are set forth in Appendix F and which are designed to produce $566,758,000 in additional base rate revenues based on the adopted test year 1983 results of operations.

2. Edison should be authorized to file revised electric rates designed to produce additional base rate revenues in the attrition year 1984 based on our adopted ARA mechanism as described in Section XI and Appendix E.

3. Edison should be authorized and directed to make such other changes in its filed tariffs as are set forth in Appendix B.

4. Edison should be authorized to revise its AER to .00253 $/kWh to produce $9,177,000 in additional revenues to recognize the adopted 12.55% rate of return.

5. Edison should be authorized to revise its CLMABF to .00027 $/kWh to produce $5,000,000 in additional revenue for the adopted RCS program.

6. Edison and staff should choose and justify forecasting methods which better match the type of growth expected for various O&M expenses.

7. Edison should identify the accrual and rate base components of recovered spent nuclear fuel disposal costs as line items in the Summary of Earnings, and should provide yearly and cumulative accrual and rate base information in future rate proceedings in a form comparable to Attachment 1 of Exhibit 121.

8. Edison should be required to phase out the Conservation Corner program as quickly as is feasible in 1983, and to reclassify the New Customer Booklet program as a Public Awareness expense.

9. Edison should be penalized the revenue equivalent of 10 basis points on its authorized return on equity in 1983 and 1984 for failing to comply with the express avoided cost policies of the Commission.

10. Edison should be ordered to normalize 1982 ACRS and ITC associated with SONGS Unit 2 in a deferred tax reserve pending the inclusion of SONGS Unit 2 in rate base.

11. The increase in rates and charges authorized by this decision is justified and is reasonable. The rate schedules set forth in Appendix F of this decision will afford Edison an opportunity to collect the additional authorized revenues in a just, reasonable, and nondiscriminatory manner.

12. The effective date of this order should be the date on which it is signed to meet Edison's need for immediate rate relief and to meet the requirements of the Regulatory Lag Plan.

13. The petitions of TURN, City of West Covina, and CVAG should be denied.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission, on or after the effective date of this order, revised tariff schedules for electric rates as set forth in Appendix F attached hereto and by this reference made a part hereof.

2. The revised tariff schedules shall become effective on the date of filing but not earlier than January 1, 1983, and shall comply with General Order 96-A.

3. The revised rate schedules shall apply to service rendered on or after the effective date of the revised tariff schedules.

4.. Edison shall send the bill insert contained in Appendix D relating to the impact of ERTA on customer rates in Edison's first billing to customers subsequent to the date the rates authorized by this decision become effective.

5. Edison is authorized to record $2,129,957,700 of California jurisdictional base rate revenues and $137,647,000 of Annual Energy Rate revenues in test year 1983 for the purposes of determining the amount to be recorded under the Electric Revenue Adjustment Mechanism authorized here.

6. Edison is authorized to file by advice letter no later than October 31, 1983 a request for the additional revenue requirement for attrition year 1984. The revenue requirement will be determined in accordance with the ARA methodology set forth in this decision. The revised rate schedules reflecting this allowance shall become effective on January 1, 1984.

7. Edison is authorized to file with this Commission revised tariffs to adjust the AER to .00253 $/kWh and the CLMABF to .00027 $/kWh on or after the effective date of this order. The revised tariff schedules shall apply only to service rendered on or after January 1, 1983.

8. Reallocation of conservation and load management funds in excess of $2.5 million among the three individual programs, or reallocation to or from the major categories of Residential Conservation, Nonresidential Conservation, and Load Management shall be made the subject of an advice letter filing.

9. Edison shall maintain a record of its conservation and load management expenditures on a program-by-program basis so that such expenditures may be readily identified, justified, and evaluated for reasonableness. Edison shall file quarterly reports which describe the progress of research on conservation measurements conducted in the prior year and research planned for the near future. The timing and format of the report shall be determined jointly by staff and Edison.

10. Edison shall phase out the Conservation Corner program as quickly as is feasible in 1983, and reclassify the New Customer Booklet program as a Public Awareness expense.

11. If Edison, as of the end of 1982 or any subsequent year, has underspent base rate funds authorized for conservation or load management programs, Edison shall seek Commission approval of its proposed allocation through an advice letter filing no later than March 1 if the amount is greater than $2.5 million or if Edison plans to reallocate funds among the three major program categories. Otherwise, Edison may allocate the money to supplement conservation expenditures in the following year as it sees fit.

12. Edison shall report no later than February 15 of each year on its conservation and load management expenditures during the prior year and its proposed budget for the current year. Any carryover amounts, and rate base, expense, and load management incentive components shall be clearly shown.

13. Pending our decision in Applications 82-01-40 and 82-03-63 regarding the amount of investment and investment-related expenses associated with SONGS Unit 2 which should be included in rate base, Edison shall normalize 1982 ACRS and ITC attributable to plant in a deferred tax reserve.

14. The Commission's General Counsel shall examine Edison's past, present, and future legal remedies relating to the costs of sleeving the steam generator tubes of SONGS Unit 1 and shall, if found appropriate on the basis of that examination, recommend disallowance of all or a portion of such costs which have been or may be included in rates. Edison shall cooperate fully with the General Counsel's examination. The General Counsel shall report the results of its examination to the Commission no later than March 1, 1983.

The final three of four annual allowances of $14.2 million included in rates to amortize Edison's SONGS Unit 1 sleeving costs shall be subject to refund.

15. Edison shall, within 60 days, file a plan for expansion of Schedule No. TOU-GS. The expanded program shall include, to the greatest extent possible, the larger General Service customers and add at least 1,000 meters per year to the system.

16. Edison shall maintain in future ECAC proceedings the approximate rate differentials by time period in Schedules Nos. TOU-8, TOU-PA-1, and TOU-GS, and the approximate differentials in the experimental time-of-use schedules authorized by this decision.

17. The petitions of TURN, City of West Covina, and CVAG are denied.

18. A final order in this proceeding shall issue pending resolution of A.82-08-10.

This order is effective today.

Dated December 13, 1982, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

I will file a concurring opinion.

/s/ JOHN E. BRYSON
Commissioner

I will file a concurring and dissenting opinion.

/s/ RICHARD D. GRAVELLE
Commissioner

I will file a concurring opinion.

/s/ LEONARD M. GRIMES, JR.
Commissioner

Due to financial interests beyond my control in potential cogenerators and small power producers in Edison's service territory, I abstain only from those portions of this decision treating Edison's failure to encourage cogeneration and small power production during 1980-1981, including specifically Finding of Fact Nos. 127, 128, 129, 130, 131, 132, 133, 134, 135, and 136, and Conclusion of Law No. 9.

/s/ PRISCILLA C. GREW
Commissioner

For the reasons set out by ALJ Sarah Myers in OIR #2, I likewise have not participated in deliberations and abstain only from those portions of this decision treating Edison's failure to encourage cogeneration and small power production during 1980-1981, including specifically Finding of Fact Nos. 127, 128, 129, 130, 131, 132, 133, 134, 135, and 136, and Conclusion of Law No. 9.

/s/ JOHN E. BRYSON
Commissioner

APPENDIX A
Page 1

LIST OF APPEARANCES

Applicant: John R. Bury, David N. Barry, Richard K. Durant, Frank J. Cooley, Carol Henningson, and James M. Lehrer, Attorneys at Law, for Southern California Edison Company.

Protestants: Hastings, Blanchard, Weiler & Kennedy, by Peter T. Kennedy, Attorney at Law, for Christian Science Churches of Southern California; and Anne Trojan, Debbie Klempa, and V. Edward Duncan; for themselves.

Interested Parties: Etta Gail Herbach, Attorney at Law, for Federal Executive Agencies; Steve Burger and Lisa Trankley, Attorneys at Law, and Gregg Wheatland, for California Energy Commission; Brobeck, Phleger & Harrison, by Gordon E. Davis, William H. Booth, and Richard C. Harper, Attorneys at Law, for California Manufacturers Association; Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association; Halina F. Osinski, Attorney at Law, for California Community and Junior College Association; James F. Sorenson, Attorney at Law, for Friant Water Users Association; Grant Nelson, for Metropolitan Water District of Southern California; Greve, Clifford, Diepenbrock & Paras, by Thomas J. Knox, Attorney at Law, for California Retailers Association; Pamela A. Summers and Gary Wiedle, for Coachella Valley Association of Governments; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Thomas E. Ross, Attorneys at Law, for California Industrial Energy Consumers; Overton, Lyman & Prince, by John A. Payne, Jr., Attorney at Law, for Southwestern Portland Cement Co.; Antone S. Bulich, Jr., Attorney at Law, for California Farm Bureau Federation; Robert W. Parkin, City Attorney, by Richard A. Alesso, Deputy City Attorney, for City of Long Beach; William L. Knecht, Attorney at Law, for California Association of Utility Shareholders; Jeffrey Lee Guttero, William L. Reed, and Randall W. Childress, Attorneys at Law, for San Diego Gas & Electric Company; Harry K. Winters, for University of California; Henry F. Lippitt, 2nd, Attorney at Law, for California Gas Producers Association; Michael Paparian, for Sierra Club; Graham & James, by Thomas J. MacBride, Jr., Attorney at Law, for California Hotel & Motel Association; Sylvia M. Siegel, Michel Peter Florio, and Robert Spertus,

APPENDIX A
Page 2

Attorneys at Law, for Toward Utility Rate Normalization; Gary David Gray and Robert C. Jones, for California Public Safety Radio Association; Kenneth A. Strassner, Attorney at Law, (Washington, D.C.) by Paige W. Randolph, Attorney at Law, for Kimberly Clark Corporation; Dorothy Boberg and Lyn Harris Hicks, for GUARD; Martin E. Whelan, Jr., Attorney at Law, for Professional Community Management, Inc. and Mutual Housing Corporations inside Leisure World; John W. Witt, City Attorney, by William S. Shaffran, Deputy City Attorney, for City of San Diego; Robert M. Loch, Thomas D. Clarke, and Jeffrey E. Jackson, Attorneys at Law, for Southern California Gas Company; Sarah Shirley, Deputy City Attorney, for City of Santa Monica; Reich, Adell & Crost, by Glenn Rothner, Attorney at Law, for Local 47, International Brotherhood of Electrical Workers, AFL-CIO; and James C. Dycus, for himself.

Commission Staff: Timothy Treacy, and James Rood, Attorneys at Law, and Bruce M. DeBerry.

(END OF APPENDIX A)

APPENDIX B
Page 1

PRELIMINARY STATEMENT (PART E)

ELECTRIC REVENUE ADJUSTMENT MECHANISM (ERAM)

1. Purpose: The purpose of this ERAM is to adjust revenues for sales fluctuations. The ERAM is not intended to adjust for the so-called billing lag.

2. Applicability: This ERAM provision applies to all bills for service under all rate schedules and contracts for electric service subject to the jurisdiction of the Public Utilities Commission.

3. Base Rates: The base rates are the rates for electric service in effect at any time, exclusive of adjustment rates for which a balance or adjustment account is specifically provided in the Preliminary Statement.

4. Authorized Base Revenue Amount: The authorized base revenue amount is the annual revenue to be collected from base rates. The authorized base revenue amount shall be increased or decreased to incorporate changes in the level of authorized revenue specified in decisions of the Commission with respect to base rates concurrently with the beginning of the period to which such revenue change applies.

5. Actual Base Revenue Amount: The actual base revenue amount shall be the revenue for service rendered each month.

6. Revision Dates: The revision dates are as provided under Part B of the Preliminary Statement (ECAC). On such dates, or as soon thereafter as the Commission may authorize, the utility shall increase or decrease the ERAM rates applicable to each rate schedule and contract in accordance with these provisions.

APPENDIX B
Page 2

7. Electric Revenue Adjustment Account: Beginning as of January 1, 1983, the utility shall maintain an Electric Revenue Adjustment Account. Entries shall be made to this account at the end of each month as follows:

a. A debit entry equal to, if positive (credit entry if negative):

(1) The authorized base revenue amount multiplied by the applicable monthly factor from the table below, less

(2) The actual base revenue amount for that month.

Month	Distribution %
January	8.28
February	7.82
March	7.93
April	7.56
May	7.78
June	8.22
July	8.98
August	8.99
September	9.29
October	8.82
November	8.29
December	8.04

b. A credit entry equal to the amount of revenue billed during the month under ERAM rates, if positive (debit entry, if negative).

c. An entry equal to interest on the average of the balance in this account after entries a and b above at the interest rate provided in Part B of this Preliminary Statement.

(END OF APPENDIX B)

APPENDIX C

Nonlabor Escalation Components and Associated Weights

BLS Code (DRI Ref)	Price Indexes	WHL L Weights (%)
05	Fuels & Related Products	.46
057	Refined Petroleum	.15
0571	Gasoline	1.87
06	Chemicals & Allied Products	1.71
07	Rubber & Plastics Products	.50
08	Lumber & Wood Products	.01
10	Metal & Metal Products	4.62
1026	Wire & Cable	.19
1042	Hand Tools	.75
11	Machinery & Equipment	9.18
114	General Purpose Machinery	.02
117	Electrical Machinery & Equipment	5.98
1178	Electronic Components	3.47
13	Nonmetallic Mineral Products	.14
14	Transportation Equipment	1.62
141	Motor Vehicles & Equipment	5.80
15	Miscellaneous Products	1.26
WPI-IND	Industrial Commodities	19.93
CPI-U	CPI All Urban	26.04
PGNP	GNP - Implicit Price Deflator	16.30
		100.00%

(END OF APPENDIX C)

APPENDIX D

Bill Insert for Southern California Edison Company Customers

N O T I C E

$103,600,000 of the recent rate increase granted to Southern California Edison Company was made nececssary by changes in tax laws proposed by the President and passed by Congress in 1981. This was the Economic Recovery Tax Act of 1981. Among its provisions was a requirement that utility ratepayers be charged for certain corporate taxes even though the utility does not have to pay them. This results from the way utilities may treat tax savings from depreciation on their plant and equipment. The savings can no longer be credited to the ratepayer, but must be left with the company and its shareholders.

For a more detailed explanation of this tax change, send a stamped self-addressed envelope to:

Consumer Affairs Branch
Public Utilities Commission
350 McAllister Street
San Francisco, CA 94102

(END OF APPENDIX D)

ATTRITION RATE ADJUSTMENT (ARA) MECHANISM WITH INDEXING

1. Purpose. The purpose of this ARA provision with indexing is to set forth a procedure by which an attrition allowance may be established for 1984. The indexing procedure applies only to labor and nonlabor expenses using the given 1983 expenses as a base.

2. Applicability. This mechanism will apply to the attrition allowance for 1984.

3. Filing. On or before October 31, 1983, the utility shall file by advice letter with the Commission the additional revenue requirements necessary to escalate the 1983 labor and nonlabor expenses by the indexing formula adopted herein.

4. Cost Categories. Changes in the cost categories subject to indexing are limited to the changes in labor and nonlabor escalation factors. All other revenue requirement effects of changes in rate base, depreciation expense, income tax, as well as financial attrition, are set forth in paragraph 6.

5. Revenue Requirement Changes: The utility shall compute and report the revenue requirement effects of the attrition allowance calculated as discussed in paragraphs 1-4.

6. The following adopted 1983 labor and nonlabor costs are subject to indexing changes:

APPENDIX E
Page 2

Revenue Requirement
($000)

(CPUC Jurisdictional)

Revenues	Use ERAM
Labor* (1983 Base for Indexing)	306,553
Nonlabor** (1983 Base for Indexing)	426,341
Fixed Attrition Items	
Depreciation Expense	42,249
Ad Valorem Taxes	3,524
Income Tax Expense	(16,915)
Rate Base	39,331
Financial Attrition	6,043

(Red Figure)

*Includes Labor-related Pensions and Benefits and Payroll Taxes.

**Excludes labor-related Pensions and Benefits.

7. Rates. Rates will be implemented for the attrition year 1984 according to the discussion in Section XII of this decision.

(END OF APPENDIX E)

APPENDIX F

Page 1

Southern California Edison Company

RATE SUMMARY

Applicant's electric base rates, energy cost adjustment billing factors (ECACBF), annual energy rate (AER), conservation load management adjustment billing factor (CLMABF), charges, and conditions are changed to the extent set forth in this appendix. These changes result from decisions in A.61138 (General Rate Case, Test Year 1983), A.82-07-10 and A.82-11-04 (ECAC proceedings), and D.82-11-086 (11/17/82) in A. Nos. 61066 and 61067, the Residential Conservation Financing Program.

Schedule D (Single Family)

	Per Meter Per Month	
Entire Territory Served		
Includes Santa Catalina Island		
Energy Charge Components		
Base Rates		
All kWh, per kWh	4.279	
Adjustment Rates		
ECACBF		
Lifeline Service, per kWh	1.601	
Non-lifeline Service, per kWh	4.553	
AER, per kWh	.253	
CLMABF, per kWh	.027	
	Lifeline	Nonlifeline
Total Rates, per kWh	6.16	9.112
Minimum Base Rate Charge	$2.00 Added	

Schedule No. DMS-1 (Multi-family Submetered)

The base rate of the single-family domestic service schedule applicable in the territory in which the multi-family accommodation is located, less $2.00 per submetered unit.

Schedule No. DMS-2 (Mobilehome Park, Multi-family Submetered)

The base rate of the single-family domestic service schedule applicable in the territory in which the mobilehome park, multi-family accommodation is located, less $5.95 per submetered mobile home.

APPENDIX F

Page 2

Schedule No. GS-1

Entire Territory Served	Per Meter Per Month
Includes Santa Catalina Island	
Customer Charge	Eliminated
Energy Charge	
Base Rates	
All kWh, per kWh	5.260 ¢/kWh
Adjustment Rates	
ECACBF, per kWh	3.756 ¢/kWh
AER, per kWh	.253 ¢/kWh
CLMABF, per kWh	.027 ¢/kWh
Total Rate, per kWh	9.296 ¢/kWh
Minimum Base Rate Charge	$5.00

Schedule No. GS-2

Entire Territory Served	
Includes Santa Catalina Island	
Combines Schedule Nos. A-7 and GS-2	
Demand Charge	
All kW of Billing Demand, per kW	$3.80
Energy Charge	¢/kWh
Base Rates, per kWh	2.760
Adjustment Rates	
ECACBF, per kWh	3.756
AER, per kWh	.253
CLMABF, per kWh	.027
Total Rate	6.796

Minimum Base Rate Charge - See Special Condition 6

Special Condition 6: Where no contract demand is involved, the monthly minimum charge shall be $100.00. Where a contract demand is involved, the monthly minimum demand charge shall be the greater of:

a. The $100.00 monthly minimum charge, or
b. A facilities charge of $1.00 per kilowatt of contract demand.

Schedule No. A-7

Combined with Schedule No. GS-2 to form new GS-2.

APPENDIX F

Page 3

Schedule No. TOU-GS (General Service)

		Charges Per Meter Per Month
		Effective 1-1-83
DEMAND CHARGE		
All kW of on-peak billing demand, per kW		$ 1.00
Plus all kW of off-peak billing demand, per kW		No Charge
ENERGY CHARGE		
All on-peak kWh, per kWh	12.533 ¢/kWh	
All off-peak kWh, per kWh	6.533 ¢/kWh	
MINIMUM BASE RATE CHARGE		$100.00

Note: Rates shown are effective rates. Included are:

	On-peak	Off-Peak
ECABF at	8.556 ¢/kWh;	2.556 ¢/kWh
AER at	.253 ¢/kWh	
CLMABF at	.027 ¢/kWh	

APPENDIX F

Schedule No. TOU-8

	Per Meter Per Month Effective 1-1-83
Customer Charge	$560.00
Demand Charge (to be added to Customer Charge):	
All kW of on-peak billing demand, per kW ...	$ 5.05
Plus all kW of mid-peak billing demand, per kW ...	0.65
Plus all kW of off-peak billing demand, per kW ...	No Charge
Energy Charge (to be added to Demand Charge):	
All on-peak kWh, per kWh	7.821
Plus all mid-peak kWh, per kWh	6.517
Plus all off-peak kWh, per kWh	5.431

Minimum Charge:
The Base Rate Demand and Energy Charges shall be subject to the minimum charges set forth in Special Condition No. 6.

Energy Charge Components	Per kWh Effective 1-1-83 On-Peak	Mid-Peak	Off-Peak
Base Rates	2.145	2.145	2.145
Adjustment Rates:			
ECACBF	5.396	4.092	3.006
AER	.253	.253	.253
CLMABF	.027	.027	.027

Special Condition No. 6:

Where no contract demand is involved, the monthly minimum charge shall be the monthly customer charge. Where a contract demand is involved, the monthly minimum charge shall be the sum of:

a. The monthly customer charge, and
b. A facilities charge of $1.00 per kW of contract demand.

Schedule No. PA-1 (Agricultural & Pumping-Connected Load Basis)

Entire Territory Served
Includes Santa Catalina Island

	Per Meter Per Month Effective 1-1-83
Service Charge:	
Two horsepower and over of connected load, per horsepower	$1.00
Energy Charge (to be added to Service Charge):	
All kWh, per kWh	7.13¢/kWh

Minimum Charge: The minimum charge shall be the monthly Service Charge.

Note: Rates shown are the effective rates. Included are:

ECACBF	3.756¢/kWh
AER	.253¢/kWh
CLMABF	.027¢/kWh

Schedule No. PA-2 (Agricultural & Pumping-Demand Basis)

Entire Territory Served
Includes Santa Catalina Island

	Per Meter Per Month Effective 1-1-83
Demand Charge:	
All kW of billing demand, per kW	$3.75
Energy Charge (to be added to Demand Charge):	
All kWh, per kWh	6.313¢/kWh

Minimum Charge:
The Base Rate Demand and Energy Charges shall be subject to the Minimum charges set forth in Special Condition No. 5.

Note: Rates shown are effective rates. Included are:

ECACBF	3.756¢/kWh
AER	.253¢/kWh
CLMABF	.027¢/kWh

APPENDIX F

Page 6

Schedule No. TOU-PA-1 (Agricultural and Pumping)

	Per Meter Per Month Effective 1-1-83
Service Charge:	
Customer Charge	$ 4.20
Plus per kVa of Transformer Capacity	1.50
Energy Charges:	
On-peak kWh, per kWh	8.213
Off-peak kWh, per kWh	5.475

Minimum Charge: The monthly minimum charge shall be the monthly Service Charge.

	Per kWh Effective 1-1-83	
	On-Peak	Off-Peak
Note: Rates shown are effective rates. Included are:		
ECACBF	5.508	2.770
AER	.253	.253
CLMABF	.027	.027

APPENDIX F

Schedule No. LS-1 (Lighting - Utility-Owned System)

Entire Territory Served
Includes Santa Catalina Island

Nominal Lamp Rating		Per Lamp Per Month Effective 1-1-83		
Lamp Wattage	Average Initial Lumens	All Night Service	Energy Curtailment Service	
			Midnight or Equivalent	Facilities Charge
Incandescent Lamps				
103	1,000	4.10	3.56	2.30
202	2,500	5.50	4.63	3.05
327	4,000	6.55	5.09	2.85
448	6,000	7.90	5.88	3.05
690	10,000	10.65	7.50	3.35
Mercury Vapor Lamps				
100	4,000	7.05	6.25	5.10
175	7,900	7.55	6.48	5.10
250	12,000	8.80	7.47	5.75
400	21,000	10.10	8.25	6.05
700	41,000	13.20	10.10	6.40
1,000	55,000	16.25	11.65	6.45
High Pressure Sodium Vapor Lamps				
50	4,000	7.20	6.60	5.25
70	5,800	7.50	6.75	5.35
100	9,500	7.95	7.08	5.50
150	16,000	8.90	7.80	6.00
200	22,000	9.60	8.33	6.35
250	27,500	10.10	8.60	6.40
400	50,000	11.45	9.50	6.70

Note: Rates shown are the effective rates. Included are:
AER at 0.253¢ per kWh.
CLMABF at 0.027¢ per kWh.
ECACBF at 3.756¢ per kWh.

Schedule No. LS-2 (Lighting --Customer-Owned Installation Unmetered)

Type of Service	Per kW of Lamp Load Per Month Effective 1-1-83
All Night Service	
Multiple Installation, per kW	$16.90
Series Installation, per kW	22.00
Midnight or Equivalent Service	
Multiple Installation, per kW	11.90
Series Installation, per kW	13.30

Energy Charge

ECACBF	3.756 ¢/kWh
AER	.253 ¢/kWh
CLMABF	.027 ¢/kWh

Schedule No. LS-3 (lighting -- Customer-Owned Installation Metered)

	Per Meter Per Month Effective 1-1-83
Energy Charge	
All kWh, per kWh	8.803 ¢/kWh

Minimum Charge

The Base Rate Energy Charge shall be subject to a monthly minimum charge of $4.50 for Multiple Service and $12.00 for Series Service.

Note: These are effective rates. Included are:

ECACBF	3.756 ¢/kWh
AER	.253 ¢/kWh
CLMABF	.027 ¢/kWh

APPENDIX F

Schedule No. LS-4 (Lighting - Street and Highway Customer-Owned Installation)

Lamp Wattage	Average Initial Lumens	Per Lamp Per Month Effective 1-1-83
High Pressure Sodium Vapor Lamps		
50	4,000	$0.81
70	5,800	.71
100	9,500	.73
150	16,000	.69
200	22,000	.70
250	27,500	.71
400	50,000	.81

Schedule No. TC-1 (Traffic Control Service)

	Per Meter Per Month Effective 1-1-83
Total Rate	8.0 ¢/kWh
Adjustment Rates	
ECACBF	3.756 ¢/kWh
AER	.253 ¢/kWh
CLMABF	.027 ¢/kWh
Minimum Base Rate Charge	$5.00

APPENDIX F

Page 10

Schedule No. OL-1 (Outdoor Area Lighting Service)

Nominal Lamp Rating: Lamp Wattage	Average Initial Lumens	Per Lamp Per Month Effective 1-1-83: All Night Service	Energy Curtailment Service: Midnight or Equivalent	Energy Curtailment Service: Facilities Charge
Mercury Vapor Lamps				
175	7,900	$ 8.20	$6.84	$5.15
400	21,000	10.95	8.73	6.10
High Pressure Sodium Vapor Lamps				
70	5,800	8.10	7.09	5.40
100	9,500	8.60	7.50	5.55
200	22,000	10.35	8.73	6.40

Pole Charge (to be added to Lamp Charge):	Per Pole Per Month Effective 1-1-83
For each additional new wood pole installed	$2.95

Energy Charge

AER at 0.253 ¢ per kWh
CLMABF at .027 ¢ per kWh
ECACBF at 3.756 ¢ per kWh

APPENDIX F

Schedule No. DWL

	kWh Per Month	Per Month
Lamp Charge:		
75 watt mercury vapor lamp, per lamp	32	$ 7.86
Minimum Charge:		
Per customer		100.00

The rate above includes a Base Rate and applicable Adjustment Rates as shown below:

Base Rate	Per Month
Lamp Charge	$6.46

Adjustment Rates	Per kWH
ECACBF	3.756
AER	.253
CLMABF	.027

Schedule No. D-PG

Net Energy Charge:	Per Meter Per Month
1st 100 kWh or less	$4.28

Minimum Charge: The monthly minimum charge shall be the charge for the 1st 100 kWh.

	¢/kWh
Base	4.279
ECACBF, LL	1.601
Non-LL	4.553
AER	.253
CLMABF	.027

Schedule No. GS-1-PG — Per Meter Per Month

Net Energy Charge:

1st 100 kWh, or less	$5.25
Excess kWh, per kWh	5.254¢/kWh

Minimum Charge: The monthly minimum charge shall be the charge for the 1st 100 kWh.

Note: The rates shown are the effective rates. These include:

ECACBF, per kWh	3.756 ¢/kWh
AER, per kWh	.253 ¢/kWh
CLMABF, per kWh	.027 ¢/kWh

Schedule No. PA-1-PG — Per Meter Per Month

Service Charge:

Two horsepower and over of connected load, per horsepower	$1 /hp

Net Energy Charge:

1st 100 kWh or less	3.09

Minimum Charge: The monthly minimum charges shall be the monthly Service Charge plus charge for the first 100 kWh.

Base	3.095 ¢/kWh
ECACBF, per kWh	3.756 ¢/kWh
AER, per kWh	.253 ¢/kWh
CLMABF, per kWh	.027 ¢/kWh

(END OF APPENDIX F)

RICHARD D. GRAVELLE, Commissioner, Concurring and Dissenting:

While I concur in this decision there are two issues on which I must respectfully dissent.

In our recent Southern California Gas Company rate decision we disallowed all expenses for dues and donations rather than attempting to analyze the nature of each recipient of such payment to determine reasonableness and relationship to necessary utility operations. The dollars involved are not large but the principle is clear and should be consistently applied. The utility has the burden of showing how and why each payment in this category should be borne by the ratepayer. In the absence of meeting that burden <u>no</u> such expenses should be allowed for ratemaking purposes. In this application I would disallow claimed dues and donation expense leaving to management and stockholders the choice of individuals and organizations who would receive such funds.

The other issue on which I dissent is the allowance of AFUDC for the abandoned fuel cell project in the ratemaking area of RD&D. While there may be more inherent risk in such a project that fact does not justify, in my mind, ratepayer support for the carrying cost associated with the out of pocket expenditures made by Edison. In the absence of some form of formal Commission sanction of the project, such as the issuance of certificate, I see no justification for ratepayers bearing that aspect of the project risk. I would disallow <u>all</u> AFUDC on the fuel cell project.

/s/ Richard D. Gravelle

Richard D. Gravelle, Commissioner

December 13, 1982
San Francisco, California

COMMISSIONER LEONARD M. GRIMES, JR., Concurring:

In concurring with this decision I will single out one issue that is especially disturbing, the necessity of taking punitive action by fining company management. This action is disturbing as it represents either a lack of communication between the company and this Commission, or an act of pure defiance. Whatever the reason, the end result is that the letter and spirit of a Commission order was disobeyed. Section 702 of the Public Utilities Code is very clear on the point:

> "Every public utility shall obey and comply with every order, decision, direction, or rule made or prescribed by the commission in the matters specified in this part, or any other matter in any way relating to or affecting its business as a public utility, and shall do everything necessary or proper to secure compliance therewith by all of its officers, agents, and employees."

If, in the event that a company takes exception to an order by this Commission, there are clear, well used, and understood remedies provided; defiance is not one of them. This company did avail itself of the procedures for review of the Commission's decisions and did not prevail in its point of view which should have been the end of the effort. We should not have been plagued with complaints from entrepreneurs wanting to be Qualifying Facilities that this company's negotiators were not playing by the Commission's rules.

Our staff in its penalty recommendation stressed that Edison has failed to achieve to a substantial degree the potential cogeneration, small power production, wind generation, and auxiliary emergency cogeneration resources of its service area. Staff's penalty would have been of much greater magnitude than that contained in this decision. I could not support the higher level recommended; but this moderation should not be seen as apologetic, but recognition of the fact that clear, objective, and measurable goals were not provided by us.

I am not against "playing hardball" especially where it is with sophisticated business people who can protect themselves and there is a clear benefit to ratepayers; but when we have prescribed a different behavior, this kind of dealing should not be attempted. The rules developed in OIR 2 provided for imaginative contracting, provided the basic standard offer for "full avoided" costs was not denied. An indication of the additional impact of company's attitude is the staff report that Edison's results in developing alternative generation resources have been, and continue to be, significantly diminished by its pricing polices--that is its failure to follow this Commission's established pricing policy rules.

/s/ Leonard M. Grimes, Jr.
LEONARD M. GRIMES, JR., Commissioner

San Francisco, California
December 13, 1982